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September 29, 2025

***VIA ELECTRONIC FILING***

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

**Re: UM 2273—PacifiCorp's Phase 2 Reply Comments**

PacifiCorp d/b/a Pacific Power encloses for filing in the above-referenced docket its Phase 2 Reply Comments.

If you have any questions about this filing, please contact Amira Thompson, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,

A handwritten signature in black ink, appearing to read "Robert Meredith".

Robert Meredith  
Director, Regulation

Enclosures

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UM 2273**

In the Matter of

PUBLIC UTILITY COMMISSION OF  
OREGON,

Investigation Into House Bill 2021  
Implementation Issues.

PacifiCorp Phase 2 Reply Comments

**I. INTRODUCTION**

PacifiCorp d/b/a Pacific Power respectfully replies to the draft order prepared by the Administrative Hearings Division (AHD) that addresses House Bill (HB) 2021’s cost cap provisions,<sup>1</sup> and responds to Commission questions raised during the August workshop, as well as recent Memorandum seeking responses to several related questions.<sup>2</sup>

PacifiCorp appreciates the Public Utility Commission of Oregon (Commission) and other parties’ continued collaboration and commitment to working through complex issues regarding the cost cap under HB 2021. Through these comments, PacifiCorp favors a process that is both simple and transparent to ensure efficient determination of any Section 10 filings. Additionally, PacifiCorp remains committed to ensuring it is taking actions to reduce greenhouse gas (GHG) emissions over time, but emphasizes that rate pressures and affordability for customers remain a top concern. The outcome of these deliberations, and potential exemption from HB 2021 GHG emissions targets is to ensure a reasonable balance between the cost of resource actions and the pace of emissions reductions. This balance needs to remain front-and-center when determining how best to implement cost cap relief under HB 2021.

**II. ASSUMPTIONS**

PacifiCorp makes several assumptions underlying these comments:

1. Utilities initiate a Section 10 proceeding, not third parties, due to lack of information.
2. The “counterfactual” portfolio is based on long-term modeling tools and includes all requirements to meet the needs of Oregon customers except for HB 2021 GHG targets.
3. The “compliance” portfolio is developed using the same tools and methods as (2), but includes compliance with HB 2021 GHG targets.

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<sup>1</sup> *In re Commission HB 2021 Investigation*, Docket No. UM 2273, Notice and Memorandum (May 27, 2025).

<sup>2</sup> Docket No. UM 2273, Memorandum (Sept. 2, 2025).

4. “Incremental” resources for compliance with HB 2021 sections 1-15 are determined at a point in time by comparing additional resource selections in the compliance portfolio as compared to the counterfactual portfolio.
5. When calculating the percentage increase in revenue requirement from HB 2021 compliance costs, the “numerator” includes all incurred or forecasted costs. These costs are represented as an annual revenue requirement (whether a power purchase agreement (PPA), or rate-based investments) consistent with typical cost-of-service ratemaking principles.<sup>3</sup>
  - a. Because the Commission’s initial guidance has interpreted the cost cap as an absolute, and not compounding, six percent increase,<sup>4</sup> the numerator does not reset to zero each Section 10 filing, or annually. Rather, subsequent filings will add incremental compliance costs for newly identified resources and update compliance costs for successive years.
  - b. Because the determination that a specific resource is relevant to the cost cap may not be reexamined,<sup>5</sup> subsequent proceedings (Section 10 filings, or other Commission tracking mechanism), will ensure the numerator reflects actual costs of previously forecasted compliance costs.<sup>6</sup>
6. When calculating the percentage increase in revenue requirement from HB 2021 compliance costs, the “denominator” serves as the baseline revenue requirement that would result without incremental actions taken for compliance. Because the determination that a specific resource is relevant to the cost cap may not be reexamined,<sup>7</sup> subsequent proceedings (Section 10 filings, or other Commission tracking mechanism), will also adjust the denominator to reflect actual costs of previously forecasted compliance costs.<sup>8</sup>

### III. COMMISSION QUESTIONS

#### A. Is the cost cap a soft floor or hard ceiling?

The Commission has asked whether ORS 469A.445 requires the Commission to grant an exemption from further HB 2021 compliance if rate impacts as a result of incurred compliance costs are expected to reach or exceed six percent of a utility’s projected revenue requirement.<sup>9</sup>

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<sup>3</sup> *E.g.*, ORS 469A.445(3) (stating the “commission shall determine the actual or anticipated rate impact for the investment or cost on the same basis and with the same treatment for similarly situated investments or costs in the most recently approved general rate case or other relevant rate making proceeding.”).

<sup>4</sup> *E.g.*, *Docket No.* UM 2273, Notice and Memorandum, at 15 (May 27, 2025) (the cost cap “does not permit an additional six percent rate increase every year”).

<sup>5</sup> ORS 469A.2(d).

<sup>6</sup> *E.g.*, ORS 469A.445(3)(b) (the Commission shall “Make any adjustments to the cumulative rate impact if the initial rate treatment was calculated on the basis of forecasted rate impact”).

<sup>7</sup> ORS 469A.2(d).

<sup>8</sup> *E.g.*, ORS 469A.445(3)(b) (the Commission shall “Make any adjustments to the cumulative rate impact if the initial rate treatment was calculated on the basis of forecasted rate impact”).

<sup>9</sup> Memorandum, at 1 (Sept. 2, 2025).

The question of law is straightforward: HB 2021’s cost cap is a soft floor. “Exceed” is a transitive verb, generally defined as “to be greater than a number or amount, or to go past an allowed limit.”<sup>10</sup> In context, if the “actual or anticipated” rate impact from incurred costs to comply with HB 2021 sections 1-15 “exceeds six percent” of a utility’s revenue requirement,<sup>11</sup> the Commission is required to exempt that utility from further compliance with the law, subject to the “narrowly tailored” and “limited in duration” language in ORS 469A.445(4)(a)-(b). This requires HB 2021 compliance rate impacts to “be greater than” or “go past” six percent of what retail rates would otherwise have been. This means that a cost cap exemption cannot be granted if compliance costs are less than, or even equal to, six percent, though the exemption could be crafted in anticipation of reaching the six percent limit during actual operations.

In practice, the cost cap under HB 2021 will be more complicated to implement, because utility investments will likely never fall at exactly six percent of a utility’s revenue requirement. The costs associated with utility investments to reduce GHG emissions will be uneven, ensuring that compliance cost impacts will be staircased, not linear. Nor is PacifiCorp planning for compliance based on the HB 2021 cost cap; for example, PacifiCorp’s 2025 Oregon Situs RFP seeks to procure resources to meet its 2030 obligations, and PacifiCorp will only evaluate cost cap considerations at the final shortlist stage, likely resulting in a pool of resources with larger than six percent cost impacts. Finally, there can be reasonable disagreements on what exactly counts as six percent of a utility’s revenue requirement. For these reasons, compliance costs will likely be just over six percent.

Yet the Commission still has an obligation to exempt utilities from further compliance once six percent is exceeded. This means that the Commission will need to issue a cost cap exemption at the earliest possible opportunity to ensure affordability is considered as utilities make progress toward meeting HB 2021 GHG emission-reduction targets.

There are several scenarios that could provide reasonable opportunities for a cost cap exemption. For example, if cumulative compliance costs of long-term resources amount to a five percent rate impact, a utility could implement short-term resource strategies with a lower overall incremental cost, to just slightly exceed six percent. A utility could consider additional purchases of existing hydroelectric generation shares, clean energy market or bundled energy purchases, natural gas dispatch restrictions, or renewable natural gas purchases). This strategy could be particularly beneficial if the costs from another long-term resource would significantly overshoot the six percent threshold if the next incremental resource is not supported by least-cost, least-risk procurement practices, or if more cost-effective long-term compliance options are anticipated to be available in future years.

Another opportunity to issue a cost cap exemption is after the next incremental resource after compliance costs exceed six percent. For example, if the cumulative compliance costs of three resources amounts to a five percent increase, and the fourth resource results in a seven

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<sup>10</sup> Cambridge Dictionary, “Exceed” (available online here: <https://dictionary.cambridge.org/dictionary/english/exceed>).

<sup>11</sup> ORS 469A.445(4).

percent increase, the Commission should grant an exemption for further compliance costs after that fourth resource—even though compliance costs would be one percent greater than the six percent threshold. This avoids any unnecessary complications from some sort of pro-rata cost cap determination of a portion of the costs of the fourth resource (to get closer to six percent). It also avoids complications from determining how to include a pro-rata share of a resource in future cost cap determinations (the numerator and net power cost (NPC) impacts in the denominator). Further, as revenue requirements are reasonably expected to increase each year, granting a cost cap exemption before the next incremental resource, resulting in compliance costs that slightly exceed six percent, provides a compliance cushion that should avoid revisiting cost cap exemptions more frequently if compliance were set closer to six percent.

**B. When is a reasonable opportunity for a Section 10 filing?**

Timing matters when determining when parties will have “sufficient” information for a cost cap filing.<sup>12</sup> As stated in the Draft Order, “utilities can and should submit section 10 filings when they have the information to do so,”<sup>13</sup> and the Commission has asked utilities to provide an illustrative timeline of how an IRP/CEP, RFP, and Section 10 proceeding would best align.<sup>14</sup>

Parties should always have adequate cost cap information after a utility has procured resources, as well as during a rate proceeding to include a given resource in rates. Yet this is too late. Given the large volume of resources necessary to hit the 2030 emission-reduction targets required by HB 2021 and limited years to do so, if a cost cap proceeding could not be initiated until after PacifiCorp procured resources (any time after signing an agreement up to a rate case), the costs of these resources would substantially exceed the law’s six percent cost cap. Due to these significant cost pressures, and the requirement for the Commission to grant a cost cap exemption when compliance costs exceed six percent,<sup>15</sup> the Commission should avoid this result.

In contrast, parties would almost always lack adequate information for a cost cap filing in a utility IRP or CEP. This is too early. These are planning documents based on proxy resources that lack adequate “forecasted” cost impacts for ORS 469A.445(1) purposes. While an IRP and CEP may provide helpful information to investigate cost cap implications—and there are opportunities to create a phased cost cap proceeding where certain cost cap assumptions or results are addressed in an IRP or CEP prior to a formal Section 10 filing—an IRP or CEP alone does not provide enough information for ORS 469A.445.

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<sup>12</sup> ORS 469A.445(1) (“An electric company or an organization that represents broad customer interests and that has a written agreement with an electric company pursuant to ORS 757.072 may request that the Public Utility Commission open an investigation to provide accounting for investments made, costs incurred or forecasted costs estimated by the electric company for the purpose of compliance with ORS 469A.400 to 469A.475. In making a request under this section, the petitioner shall provide information regarding the investments or costs sufficient to determine whether the investments or costs contribute to compliance with ORS 469A.400 to 469A.475.”) (underlined added).

<sup>13</sup> Notice and Memorandum, at 11.

<sup>14</sup> Memorandum, at 2.

<sup>15</sup> ORS 469A.445(4).

Given these realities, the best opportunity to initiate a Section 10 filing and begin to deliberate on specific topics is as soon as an IRP/CEP is filed, up until the time when a utility has identified a final short list (FSL) of resources in a competitive request for proposals (RFP) process, though prior to committing to any resources. This would allow parties and the Commission to begin investigating key issues in the IRP/CEP that will help the Commission determine whether a resource is selected “but for” HB 2021 compliance.

Once specific FSL resource and cost information is available, all proxy analyses from the IRP/CEP can be refreshed to examine what resources and costs are truly “but for” HB 2021 compliance. and promptly provided.

For example, PacifiCorp plans to procure the substantial majority of resources needed to either reach the 2030 emission-reduction requirements under HB 2021 or trigger the law’s cost cap with the current 2025 Oregon-Situs RFP. The company plans to identify a final shortlist from this RFP and immediately request Commission review and approval for cost cap purposes. The Commission will then be in the best position to mitigate cost impacts as close to the law’s six percent exceedance threshold as possible. While reasonable minds will likely disagree on how best to calculate six percent, a Commission decision on this issue before procurement ensures a utility neither materially under- or over-procures resources.

If the Commission agrees that a Section 10 filing may be most appropriate after a final short list has been identified, though prior to procuring these resources, PacifiCorp requests the Commission establish a fast-track proceeding to enable the Company to expeditiously move forward with resource procurement. This avoids costly contract provisions that would be needed to keep firm pricing, among other provisions, in place for a typical 8-10 month contested case proceeding to resolve. In the context of an RFP, a prolonged Section 10 process could necessitate bid refreshes and could potentially undermine the acknowledgment of the final shortlist, given market expectations that bid pricing can only be held for a limited period.

An example fast-track proceeding could look like the following:

1. Utility files an IRP/CEP, which could identify a resource need for resources to comply with HB 2021, and if so, analyses of the likelihood of hitting the cost cap. Similar to current certificate of public convenience and necessity proceedings, the IRP/CEP could provide advance notice of any anticipated cost cap proceeding. Once the IRP/CEP is filed, the parties could work through:
  - a. Modeling and assumptions for the counterfactual portfolio,
  - b. Calculation of the annual revenue requirement (ARR) for relevant years (denominator),
  - c. Treatment of existing resource costs previously determined to be included in the cost cap for HB 2021 compliance (in the numerator and the denominator), and,
  - d. Resource allocation assumptions.
2. Utility issues an RFP to procure resources to meet the needs of Oregon customers identified in IRP/CEP, **and** initiates a Section 10 Cost Cap Proceeding. Typical of Commission contested case proceedings, the moving party would file its application with

- supporting testimony and evidence, and would retain the burdens of proof and persuasion to support its case.
3. Utility files for approval of a FSL **and** updates Section 10 proceeding with actual resource information and forecasted cost impacts of HB 2021 compliance, seeking simultaneous acknowledgement of FSL and a Section 10 cost cap determination (*roughly 4 months after issuing RFP to market in step 2*).
  4. Commission issues acknowledgement or non-acknowledgement of FSL and a Section 10 determination (*within 60-90 days from step 3*):
    - a. Commission acknowledges, or not, the FSL recommendation.
    - b. Commission determines whether resources or shares of resources in the FSL are necessary to comply with HB 2021, to be accounted for in the numerator.
    - c. Commission determines whether the forecast of cumulative rate impacts is sufficient to warrant a cost cap exemption from HB 2021 compliance in specific years, and conditions the exemption as appropriate under ORS 469A.445(4)(a)-(b).
  5. After steps 4(a)-(c), a utility moves forward with relevant procurement decisions. Either (a) procuring enough resources to comply with HB 2021 emissions reductions requirements, i.e. executing contracts included in the FSL; or (b) knowingly under-procuring, understanding the utility has been granted a limited cost cap exemption with any relevant conditions.

PacifiCorp believes this fast-track proceeding is possible for three reasons. First, prudence is reserved for future rate cases, and not relevant for a Section 10 filing.<sup>16</sup> This limits the scope of contested issues: Do forecasted HB 2021 compliance costs from the proposed resource(s) exceed six percent of a utility's revenue requirement? A Section 10 filing is thus much narrower than a rate case.

Second, the Commission initially only needs to determine if a resource contributes to HB 2021 compliance and should be considered in the cost cap determination.<sup>17</sup> This means that a Section 10 filing only resolves conclusively what resources are in. It does not need to reach the question of what resources are out and does not necessarily need to conclusively identify rate impacts at the same time. For example, after it has been determined that a resource contributes to HB 2021 compliance, the rate impact associated with that resource could potentially be found to be zero as part of a later rate proceeding. While rate impacts can be determined later, compliance waivers still need to be in place in time for a utility to adjust its actions, but those waivers could be narrowly tailored to specific actions. Forecasted rate impacts developed in RFP proceedings could support a waiver that exempts a utility from additional long-term resource procurement (e.g. in excess of the final shortlist) for a one- or two-year period, while retaining obligations to pursue short-term emissions-reduction compliance measures. The cumulative rate impact

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<sup>16</sup> ORS 469A.445.

<sup>17</sup> ORS 469A.445(2)(d) ("Except as provided under ORS 756.610, a determination by the commission that an investment or cost contributes to compliance with ORS 469A.400 to 469A.475 is final and may not be reexamined.").

associated with Commission-designated compliance resources could be evaluated as part of existing rate proceedings, such as a transition adjustment mechanism or renewable adjustment clause filing. The requirement that the Commission’s compliance waivers be limited in duration is reasonably aligned with the one year forward scope of these proceedings, both of which are already contested cases.

Finally, the Commission can also decline to address overly contested issues, and reserve the issue for a subsequent cost cap proceeding, though this could obligate the utility to take additional compliance steps in the interim. This could be accomplished by declining to make a decision on whether a specific resource contributes to the cost cap, and signal that the Commission decision does not prejudice a party’s right to re-raise the issue in a subsequent proceeding. Similarly, the Commission could consider extending the procedural schedule in the proceeding to address only those more contested issues, after issuing a decision on less contested resources. While reasonable minds can disagree on when the HB 2021 compliance cost threshold is exceeded, there will be substantially less disagreement over the first several resources identified in a FSL where the cumulative rate impact is far less than six percent.

A fast-track Commission decision on resources that clearly fall under the cost cap could avoid an 8-10 month contested proceeding on all resources to determine when exactly the six percent threshold is exceeded.

**C. What evidence would allow appropriate investigation of HB 2021 compliance costs, while ensuring prompt and timely resolution?**

The Commission has asked “what evidence would be appropriate in a section 10 proceeding with respect to (a) costs that have already been incurred and (b) new expenditures?”<sup>18</sup>

To ensure fast-track resolution of Section 10 filings, the Commission should strive to simplify the burden of proof required. For PacifiCorp, this means prioritizing reaching a decision on whether a given resource is “for the purposes of” and “contributes to compliance with” HB 2021, *not* on overly scrutinizing absolute revenue requirement impacts, or getting compliance costs exactly right.

This approach is preferable because HB 2021 provides two corrective mechanisms to true-up forecasted cost impacts in subsequent Section 10 filings. First, the Commission shall “make any adjustments to the cumulative rate impact if the initial rate treatment was calculated on the basis of forecasted rate impact.”<sup>19</sup> This requires estimates of compliance cost impacts to be revised in future years based on actual rate impacts, similar to current forecasted NPC proceedings. Second, the law allows customer groups to initiate Section 10 filings to evaluate

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<sup>18</sup> Memorandum, at 1.

<sup>19</sup> ORS 469A.445(3)(a).

compliance costs.<sup>20</sup> If the Commission approves forecasted compliance costs that, in subsequent years are off-mark, customer groups can initiate a proceeding to revisit these decisions.

These options provide remedies to correct inevitable errors in forecasted compliance costs and helpfully lowers the importance of Section 10 filings getting compliance costs exactly right. In addition, while the determination that a resource contributes to HB 2021 compliance cannot be revisited, that is merely a determination that incremental rate impacts associated with a resource should be evaluated, and not a determination that the resource in question will result in incremental rate impacts at that time or in the future.

With this initial context, PacifiCorp believes the following evidentiary and simplifying assumptions should apply for Section 10 filings. For IRP/CEP modeling, including HB 2021 compliance and counterfactual portfolios, a utility should use similar methodologies from the most recent IRP/CEP. The primary function of the IRP/CEP for Section 10 purposes is to identify whether there is a need for resources, and whether those resources are driven by HB 2021 or other Oregon-specific compliance obligations. If there is an identified need for HB 2021 resources, parties can investigate typical modeling assumptions, and inputs and outputs. If the utility has diverged from prior methodologies, for example as PacifiCorp's 2025 IRP has taken a unified portfolio modeling approach as directed by the Commission from the 2023 IRP, it should explain its rationale, and parties should have the ability to investigate these new methodologies.

Hopefully, before entering a Section 10 filing, there should be general consensus, though likely not yet formal acknowledgement or a continual progress decision, whether a utility has a need for HB 2021 resources, which should limit the scope of contested issues in the cost cap filing.

When a specific Section 10 filing is made, PacifiCorp recommends several simplifying assumptions.

For compliance cost impacts in the numerator, the Commission should use: (a) contract bid commercial operation deadline, which can be revisited in subsequent years if project falls out or misses the commercial operation date; and (b) use RFP bid terms, as executed terms would not be available at the time of a Section 10 filing, to determine annualized revenue requirement impacts. Actual costs (for example, final pricing or capacity factors), can be updated in subsequent Section 10 filings as allowed under ORS 469A.445(3)(a).

For revenue requirement impacts in the denominator, the Commission should use: (a) the last commission-approved rate case revenue requirement, potentially adjusted for known and measurable material changes (like resources approved in a Renewable Adjustment Clause); (b) last commission approved NPC, again potentially adjusted for known and measurable material changes. NPC is discussed in greater detail below.

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<sup>20</sup> ORS 469A.445(1).

Hopefully, these simplifying assumptions can focus a Section 10 proceeding on determining what costs are truly incremental compliance costs, the core issue of a Section 10 filing. While there are other implementation issues that the Commission would need to walk through in future cost cap proceedings (for example, how does the counterfactual work in subsequent cost cap filings) those issues seem too fact-specific at this stage to offer concrete guidance.

#### **D. How should NPC factor in to cost cap determinations?**

HB 2021 requires that revenue requirement impacts should be calculated “on the same basis and with the same treatment for similarly situated investments or costs in the most recently approved general rate case or other relevant rate making proceeding.”<sup>21</sup> The Commission must account for any net NPC impacts in the denominator, “as adjusted by any change in net costs expected or foreseeable at the time of inclusion.”<sup>22</sup>

This means that in any Section 10 filing, the most recently approved NPC should be included in the denominator. Regarding future year’s forecasts of ARR, PacifiCorp only forecasts NPC one year a time. Any forecast beyond that period will be imperfect. The simplest solution is to treat all components of ARR similarly and take current year ARR (based on current year NPC) and use an agreed-upon inflation rate to escalate ARR for future years. As time moves on, the ARR forecast will change with any changes in NPC that may be driven by the addition of incremental resources for HB 2021 compliance. Like for example, if the addition of significant new wind resources drives down market purchase or fuel costs, those NPC benefits will flow through over time and in future cost cap determinations.

To ensure a correct application of the cost cap relative to overall revenue requirement, PacifiCorp recommends that the same rate impact determined by the Commission for compliance resources be reflected in the numerator and be subtracted from the denominator. The most straightforward determination of revenue requirement will be to use a version that already exists for other purposes, e.g. from current ratemaking processes which include all costs. Such a revenue requirement would already include HB 2021 compliance costs and would need to be reduced to identify what revenue requirement would exist in the absence of HB 2021 rate impacts. To the extent the rate impact in the numerator and the reduction in rates in the denominator are the same number they can be reduced mathematically, such that when HB 2021 compliance costs reach 5.661 percent of overall revenue requirement, they will represent six percent of revenue requirement excluding HB 2021 compliance.<sup>23</sup>

For example, in any Section 10 determination, the Commission will decide whether a resource, in its entirety or a portion, and associated costs were incurred for the purpose of, and contributes to compliance with, HB 2021. Once this initial determination is made, the rate impacts associated with that resource will be included in the numerator for subsequent cost cap

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<sup>21</sup> ORS 469A.445(3).

<sup>22</sup> ORS 469A.445(3)(a).

<sup>23</sup>  $5.661\% / (1 - 5.661\%) > 6\%$ .

filings for the life of the asset, to determine cumulative compliance cost impacts compared to any specific year ARR.

To illustrate this point, assume that a Section 10 determination concluded that a 100-megawatt (MW) wind PPA, coming online in 2030, fell under the cost cap. This 100 MW PPA has an estimated incremental cost of \$20/MWh, with a 30 percent capacity factor, increasing revenue requirement by roughly \$5.26 million per year. A subsequent Section 10 proceeding occurs in 2032 for an additional HB 2021 resource (a 100 MW solar PPA, with an estimated incremental cost of \$30/MWh, with a 25 percent capacity factor, increasing revenue requirement by roughly \$6.57 million per year). Because the entire cost of PPAs is included in net power cost, overall revenue requirement will already include the incremental cost for both of these resources. The numerator must include the cumulative compliance costs from the 2030 resource and the 2032 resource, while the denominator will need to be reduced by those same values.

In this scenario, if the numerator for 2032 is \$11.83 million (\$5.26 million from the 2030 resource, and \$6.57 million in 2032), and the total revenue requirement is \$1.8 billion, the rate impacts amount to 0.662 percent.<sup>24</sup> However if the numerator only included the \$6.57 million from the 2032 resource, the rate impact is 0.366 percent. This demonstrates how the numerator needs to include cumulative HB 2021 compliance costs, and how the denominator also needs to be adjusted for those costs. Otherwise it would skew the results of any Section 10 cost cap determination. Similar issues arise if the denominator were to include anything beyond net NPC impacts—as it would *inflate* the denominator, and as a result, *reduce* rate impacts resulting from compliance costs in the numerator.

To the extent the incremental cost of the 2030 wind resource has changed by 2032, the numerator and the denominator could be modified to reflect a more recent estimate, as HB 2021 allows the Commission to adjust for “any change in net costs expected or foreseeable at the time of inclusion.”<sup>25</sup>). Depending on the Commission’s interpretation, changes foreseeable at the time of inclusion might reflect either a static dollar value or a more dynamic value that reflects one of the following options:

1. The stream of annual net cost impacts projected for an HB 2021 compliance resource in the Section 10 compliance proceeding.
  - a. Because the actual output of many resources is expected to vary over time, instead of a stream of annual costs, the annual cost per megawatt-hour at the time of the Section 10 compliance proceeding could be applied to a more recent forecast of generation.
  - b. Changes in market prices and thus the energy value of resources are also to be expected, and the rate impacts for HB 2021 compliance resources could be recalculated based on current market conditions, for instance as forecasted in annual net power cost updates.

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<sup>24</sup>  $\$11.83\text{m} / (\$1.8\text{b} - 11.83\text{m}) = 0.662\%$ .

<sup>25</sup> ORS 469A.445(3)(a).

2. Capacity value is also likely to be volatile over time, as a result of changing capacity resource options and costs as well as changing capacity contribution values both for the HB 2021 compliance resource and various potential alternatives. While it is theoretically possible to account for all of these changes, capacity value is often tied to long-term resource decisions that must be made with the information and options that are available. As such, it may make sense to lock in capacity value assumptions at the time of the Section 10 compliance proceeding.

One point of caution on dynamic interpretations of HB 2021 rate impacts, consider a utility whose HB 2021 compliance cost is expected to be at the cost cap at the time of the net power cost proceeding for the next year. A sudden spike in market prices which increases the energy value of compliance resources could simultaneously reduce the numerator and increase the denominator. Even if market prices only impact the denominator, this could leave a utility short of the six percent cost cap on an actual basis, forcing it to take additional compliance measures sufficient to ensure rate impacts remain at six percent. Customers could thus face increased compliance costs at the same time they face increased costs from power cost true-ups. To forestall this situation, the compliance position of a utility and appropriate limits on its necessary compliance measures should be identified in advance, based on anticipated cumulative rate impacts.<sup>26</sup>

#### IV. IMPLEMENTATION ISSUES

##### A. Multi-State Implications

Under the law, a Section 10 filing will determine what volume of resources might exceed the HB 2021 cost cap. That decision requires the Commission to determine whether the investments or costs were “for the purpose of” and “contribute to compliance with” ORS 469A.400 to 469A.475.<sup>27</sup> After determining that a specific cost is relevant to the HB 2021 cost cap, the Commission needs to determine how that cost will impact the Oregon-specific retail revenue requirement for that utility.<sup>28</sup> This analyses must use “cost allocation methodologies for attributing rate impacts of investments or costs for multistate electric companies.”<sup>29</sup> If those costs exceed six percent of the revenue requirement, a utility “shall” be exempt from further compliance with HB 2021, subject to the conditions in ORS 469A.445(4)(a)-(b).

Under these requirements, a Section 10 filing must address multi-state cost allocation issues. Start with the first step. Reviewing whether an investment or cost was for the purpose of, and contributes to compliance with, HB 2021 necessarily requires the Commission to determine whether, and to what extent, the investment or cost was required by HB 2021.

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<sup>26</sup> ORS 469A.445(4).

<sup>27</sup> *E.g.*, ORS 469A.445(1).

<sup>28</sup> ORS 469A.445(3).

<sup>29</sup> ORS 469A.445(3)(d).

This is a sorting exercise that requires the Commission to exclude resources that are not relevant to the cost cap, including Oregon-specific assets that are unrelated to HB 2021 (like resources to satisfy PacifiCorp's existing small scale renewable obligation), or system assets (like new transmission lines needed for reliability purposes). It would also require the Commission to address whether a resource serves a single purpose (to comply with HB 2021), or that serves a dual purpose (*e.g.*, it is HB 2021 compliant, and also meets a system need), and determine what percentage of the resource is relevant for the cost cap.

The point here is that in each of these scenarios, the Commission needs to determine what portion of a resource was required by HB 2021, a state-specific policy. Regardless, if the answer on any given asset is zero or 100 percent, the Commission needs to address this threshold determination for each Section 10 filing.

Assuming the Commission declined to address cost allocation under ORS 469A.445(1), the Commission could not avoid the issue under ORS 469A.445(3). In this second step, after determining that an asset falls under the cost cap, the Commission needs to determine actual or forecasted Oregon retail revenue requirement impact. Putting aside complications that will arise from calculating appropriate rate impacts, the primary factor in this calculation are the costs in the numerator (relevant HB 2021 compliance costs), and what portion of a given resource would be relevant for PacifiCorp's Oregon retail revenue requirement.

PacifiCorp believes it is not possible to evaluate cost impacts to Oregon customers without determining what percentage of a specific HB 2021 resource would serve those customers. For that reason, HB 2021 requires the Commission to address multi-state cost allocation issues in a Section 10 filing.<sup>30</sup> Of course, what amount of a resource was reasonably and prudently incurred for rate recovery purposes is reserved for future proceedings, ORS 469A.445(5), but a Section 10 filing must address whether any given resource was an Oregon-situs resource or not. And when that determination is made, under the 2020 Protocol, all state-specific resources would be situs assigned to Oregon as an investment or cost required to satisfy HB 2021, a state-specific policy.

This issue has taken on more importance given the Commission's actions in UM 2383. In that docket, the Commission approved Staff's memo, which relevant here, was concerned that an Oregon-Situs RFP would result in "premature cost allocation assumptions."<sup>31</sup> To that end, the Commission adopted Staff's recommendation for PacifiCorp to "revise its Oregon RFP . . . so that the Oregon shortlist process has on-ramps to incorporate projects that are shortlisted in Washington and participate in both RFPs."<sup>32</sup> This means that cost-allocation issues have been delayed until future proceedings. This is contrasted with Washington, where that state

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<sup>30</sup> ORS 469A.445(3)(d).

<sup>31</sup> *E.g.*, Order No. 25-343, Appendix A, at 4.

<sup>32</sup> *Id.* at 9.

commission approved PacifiCorp's 2025 Washington Situs RFP, largely to procure resources to comply with clean energy targets set by that state.<sup>33</sup>

Given this development, a Section 10 filing in Oregon is the last reasonable opportunity to address multi-state cost-allocation issues resulting from the 2025 Oregon-Situs RFP. PacifiCorp expects it may need to make a Section 10 filing immediately after identifying a final shortlist of resources from the 2025 Oregon-Situs RFP. If the Commission declines to address multi-state cost-allocation issues in that Section 10 filing, PacifiCorp would have to determine what volume of resources to procure in the RFP based on a currently unknown future need, or assignment of costs.

Focus on generation resources. Assume one gigawatt (GW) of resources would trigger the HB 2021 cost cap, PacifiCorp would have to decide whether to procure one GW of Oregon-situs resources, or 3.72 GWs of system resources (assuming Oregon is allocated the current year 26.88 percent share of these resources under the 2020 Multi-State Protocol).

Either option presents extreme and unmanageable compliance risks. For the first example, if the company procures one GW of resources without knowing whether those resources satisfy the HB 2021 cost cap and not having the ability to resolve that issue until a future rate proceeding, the Commission may ultimately conclude that the one GW of resources are system resources. In that event, while PacifiCorp would likely recover all or a portion of Oregon's system share of the one GW of resources, PacifiCorp would not have procured adequate resources to trigger the HB 2021 cost cap, nor meet HB 2021 GHG emission – reduction targets. As a result, PacifiCorp would likely be subject to administrative penalties. And given there is no need for system generation resources at this time,<sup>34</sup> the company's ability to recover the non-Oregon system share of this one GW of resources from other states would be subject to material disallowance risk as imprudent utility investments.

In the second example, if the Company procures 3.72 GWs of resources on the assumption that Oregon's system share of these resources would trigger the cost cap, PacifiCorp would have to seek recovery of the additional 2.72 GWs of resources from PacifiCorp's other five states. Given there is no need for system generation resources at this time, these resources would also be subject to material disallowance risk as imprudent utility investments.

The most likely result of the Commission declining to address multi-state cost-allocation issues in a Section 10 filing is that PacifiCorp would have to consider how, and if, it were

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<sup>33</sup> *E.g., In re PacifiCorp's 2025 Draft Washington Situs RFP*, Docket UE-250460, Order 02, ¶ 26 (“As we have discussed in prior orders, PacifiCorp needs additional CETA compliant resources to meet Washington load and to shift away from what has long been characterized as an over-reliance on market resources to serve Washington.”); *Id.* ¶ 29 (approving PacifiCorp's “Draft 2025 Washington Situs Request for Proposals”).

<sup>34</sup> *E.g., In re PacifiCorp's 2025 Oregon RFP*, Docket No. UM 2383, Response Comments, at 5 (Jul. 24, 2025) (“Excluding demand response and energy efficiency resources, Oregon has a demonstrated need for approximately 3.6 gigawatts (GW) by 2030, Washington has a need for approximately 2 GW, while UIWC only has a need for 429 megawatts (MW)—with no generation resources before 2029, and only new battery storage having a duration that is less than 8 hours.”).

possible to move forward with procuring resources from the 2025 Oregon-Situs RFP. PacifiCorp is not willing to assume the risks of either (a) likely recovery of a portion or all of Oregon's system share of one GW of resources, but potential administrative penalties in Oregon for under-procurement, no cost cap exemption, and disallowance in Washington, California, Idaho, Utah, and Wyoming; or (b) receiving a successful cost cap exemption, and likely recovery of Oregon's system share of 3.72 GWs of resources, but disallowance of the remaining 2.72 GWs in PacifiCorp's other states.

PacifiCorp urges the Commission to avoid creating a situation where PacifiCorp is forced to seek recovery of HB 2021 resources from other states. To that end, the Commission should affirmatively address multi-state cost-allocation issues in any Section 10 filing—if not earlier.

## **B. Transparency**

During the cost cap workshop, Commissioner Power stressed, given the current planning and procurement environment that will continue to be impacted by recent federal trade and tax policies, the need to ensure transparency around utility modeling in Section 10 filings. OSSIA also stresses that stakeholders need to have adequate opportunity to review and investigate utility modeling.<sup>35</sup>

PacifiCorp agrees. The functionality provided by sophisticated modeling software like PLEXOS will result in more accurate and precise cost cap determinations. Yet it can be difficult for parties to effectively and efficiently engage with these modeling assumptions and results—especially if the Commission adopts a fast-track Section 10 proceeding as PacifiCorp has requested.

PacifiCorp recommends three suggestions to support more transparent Section 10 analyses.

First, just as in the 2025 CEP, PacifiCorp intends to include counterfactual portfolio analyses that examine incremental compliance costs with and without HB 2021 in future CEP filings. While there are many reasonable instances where modeling for a Section 10 filing diverges or evolves from the analyses included in the most recent IRP and CEP (just as PacifiCorp's 2025 CEP incorporated more recent information compared to the previously filed 2025 IRP), stakeholders will have had at least an initial opportunity to review PacifiCorp's No-HB 2021 counterfactual in the most recent CEP. In instances like the current planning cycle where a CEP is filed well in advance of a Section 10 filing, this provides parties with adequate opportunities to begin investigating relevant modeling assumptions and results.

PacifiCorp stresses, however, that because PacifiCorp's 2025 CEP No-HB 2021 counterfactual was created before Commission guidance in this proceeding, the company's Section 10 filing will incorporate whatever requirements that results from the Commission's decision on these issues. PacifiCorp's 2025 CEP No-HB 2021 counterfactual should not

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<sup>35</sup> OSSIA In. Comments, at 1-2 (Aug. 12, 2025).

establish precedent for what cost assumptions or analyses are relevant at the time of a Section 10 filing.

Second, PacifiCorp plans to provide supporting PLEXOS workpapers with its initial Section 10 filings, just as the company currently does for IRP proceedings. This will provide more information to stakeholders than what the Commission requires for rate proceedings that also involve PLEXOS modeling. For example, in each of PacifiCorp's most recent rate proceedings, the 2024 general rate case (UE 433) and current Renewable Adjustment Clause (UE 451), PacifiCorp provided pre-filed written testimony that relied on PLEXOS modeling. Yet PacifiCorp did not provide supporting PLEXOS workpapers in those proceedings. While no party requested this information in subsequent discovery in those proceedings, PacifiCorp proposes to do so with Section 10 filings to increase transparency.

Third, as noted during the Commissioner workshop, PacifiCorp would support technical workshops on PLEXOS modeling, analyses, and results, to inform stakeholder and Commission review in a Section 10 proceeding (or in a CEP, for that matter). While a workshop may be less helpful in a typical 8-10 month contested case schedule, there could be significant benefit for a workshop in a fast-track proceeding that is resolved in less than 120 days. Parties would have the ability to quickly resolve clarifying questions or issues without formal discovery, hopefully narrowing the scope of contested issues and maintain a fast-track proceeding.

When paired with well-worn procedural rights to investigate utility assumptions and modeling, and cross-examine utility subject matter experts under oath during a contested case Section 10 evidentiary hearing,<sup>36</sup> PacifiCorp believes these suggestions provide sufficient transparency and opportunities to investigate utility cost cap analyses.

## V. ADDITIONAL ISSUES

PacifiCorp would also like to raise several additional issues for Commission consideration, as well as respond to certain issues from stakeholder initial comments.

First, NW Energy Coalition and Renewable Northwest (NWEK/RNW) state that any HB 2021 counterfactual portfolio should account for risks, for example like supply and price volatility of gas prices and new gas plants, and recommends the Commission require utilities to incorporate the social cost of greenhouse gases (SCGHG).<sup>37</sup>

Regarding natural gas volatility, least-cost, least-risk planning and procurement processes already account for this volatility. In the 2025 IRP and 2025 CEP, PacifiCorp applied daily scalars to the natural gas price forecast to account for natural gas price volatility in all model runs. In the 2025 IRP, PacifiCorp also analyzed portfolios using low, medium, and high natural gas prices. This provides a range possible gas futures, each made internally consistent through third-party analytics. Stochastic runs incorporated actual volatility in natural gas prices from

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<sup>36</sup> E.g., ORS 469A.445(2) (indicating a Section 10 filing will adhere to Commission contested case requirements).

<sup>37</sup> NWEK/RNW In. Comments, at 5-6 (Aug. 12, 2025).

eighteen years of historical data. These views of gas futures, combined with stochastic price volatility, inform the range of outcomes that might occur outside of the expected case.

Beyond these planning processes, PacifiCorp notes that natural gas volatility would be a fact-specific issue that is best reserved for an actual Section 10 filing. The Commission should avoid prejudging which types of issues (like natural gas volatility) or analyses may or may not be relevant in a cost cap proceeding. As a party, NWEA/RNW would have the full rights to appear and be heard,<sup>38</sup> and can raise these issues as appropriate in a relevant cost cap filing.

Second, regarding the SCGHG, PacifiCorp represents this is prohibited by law. HB 2021 requires the Commission to account for actual and forecasted costs “on the same basis and with the same treatment for similarly situated investments or costs in the most recently approved general rate case or other relevant rate making proceeding.”<sup>39</sup> The Commission has not approved the inclusion of a SCGHG carbon adder for any generation, transmission, or distribution asset in Oregon. If the Commission were to require utilities to include the SCGHG in a No-HB 2021 counterfactual, that would conflict with ORS 469A.445(3) which requires adherence to typical ratemaking treatments. There are also significant policy, implementation, and cost concerns with this recommendation that cannot be addressed without development of an evidentiary record. PacifiCorp requests the Commission decline to address this concern.

## VI. CONCLUSION

PacifiCorp continues to appreciate the Commission’s diligent efforts with HB 2021-related issues, and respectfully requests the Commission consider the issues discussed above. To inform the company’s procurement efforts in the 2025 Oregon-Situs RFP, PacifiCorp requests the Commission issue guidance before the end of the year.

Respectfully submitted September 29, 2025,

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<sup>38</sup> ORS 469A.445(2)(a).

<sup>39</sup> ORS 469A.445(3).