ORDER NO. 26-028

ENTERED Jan. 30, 2026

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.	ORDER

DISPOSITION: DETERMINATIONS MADE WITH RESPECT TO HOUSE BILL 2021 COST CAP

In this order, we resolve threshold legal and procedural issues and answer questions identified in Order No. 24-002 related to the cost cap provisions contained in House Bill 2021 (2021).[1] In addition, we direct the Administrative Hearings Division to open a rulemaking docket to define key elements of the evaluation and develop appropriate simplifying assumptions.

I. BACKGROUND

To help mitigate rate increases resulting from HB 2021's emission reduction targets, the legislature included a "cost cap" provision that allows electric utilities to be temporarily exempt from further compliance if the cumulative impact of their compliance costs[2] on customer rates exceeds six percent in a given year. The cost cap, set forth in section 10 of HB 2021, establishes a process for a Commission investigation to determine the actual or anticipated cumulative rate impact of actions taken by an electric company to comply with sections 1 through 15 of HB 2021.

[1] ORS 469A.445 (section 10).

[2] While we refer throughout this order to "HB 2021 compliance," we acknowledge and remind stakeholders that HB 2021's cost cap applies only to "investments made, costs incurred or forecasted costs estimated by the electric company for the purpose of compliance with ORS 469A.400 to 469A.475" (i.e., sections 1 through 15 of HB 2021). ORS 469A.445(1). This excludes any costs associated with compliance with the statute's remaining twenty-five sections; for example, energy purchases from small-scale renewable energy projects to comply with ORS 469A.210 do not count toward the cost cap.

In Order No. 24-002, we identified four areas in need of clarification related to the Commission's calculation of actual or expected costs of compliance for purposes of the cost cap. First, we noted that the legislature used two different phrases to describe applicable investments and costs. While ORS 469.445(1) describes investments and costs "for the purpose of compliance," ORS 469.445(1)-(3) refers to whether an investment or cost "contributes to compliance."

Second, we noted that the legislature requires the Commission to consider not only investments made and costs incurred but also "forecasted costs estimated by the electric company." We described that forecasted costs could mean both costs yet to be incurred from an action already taken, as well as costs arising from other compliance actions proposed but not yet taken.

Third, we highlighted that HB 2021's cost cap does not address possible interactions with the cost cap contained in Oregon's Renewable Portfolio Standard (RPS). Similarly designed to help manage costs while encouraging renewable energy adoption, the RPS cost cap provides exemptions if the costs of complying with the RPS exceed four percent of the utility's revenue requirement in a year. HB 2021 does not clarify how the Commission should treat investments and costs for actions that are required to meet both HB 2021's emissions targets and the RPS.

Finally, we identified uncertainties related to the calculation of rate impacts arising from compliance action. We questioned whether the legislature intended that the cost cap apply only in individual years, based solely on the relevant costs experienced in a single year as a percentage of that same year's revenue requirement.

To address these uncertainties, we opened the second phase of this docket and asked the parties to provide legal briefing on the four identified issues. The following parties submitted opening briefs on May 23, 2024: Oregon Citizens' Utility Board (CUB), Alliance of Western Energy Consumers (AWEC), NewSun Energy (NewSun), Portland General Electric Company (PGE) and PacifiCorp (joint brief), Northwest Energy Coalition (NWEC) and Renewables Northwest (RNW) (joint brief), and PacifiCorp (supplemental brief). Reply briefs were filed by the following parties on June 20, 2024: AWEC, NewSun, PGE and PacifiCorp (joint brief), and NWEC and RNW (joint brief).

On May 27, 2025, the Administrative Law Judge issued a memorandum requesting comment on a draft order and a hypothetical scenario. The following parties submitted opening comments on August 12, 2025: AWEC, CUB, NewSun, NWEC and RNW (jointly), OSSIA, PacifiCorp, and PGE. On August 28, 2025, parties discussed the issues at a workshop held as a special public meeting of the Commission. Parties participating in the workshop included: AWEC, CUB, NewSun, NWEC and RNW (jointly), OSSIA, PacifiCorp, and PGE. On September 2, 2025, the Administrative Law Judge issued a memorandum requesting that parties address certain questions in their reply comments. The following parties filed reply comments on September 29, 2025: AWEC, CUB, Green Energy Institute, NewSun, NWEC and RNW (jointly), PacifiCorp, and PGE.

II. INITIATION OF RULEMAKING

As demonstrated by the briefs and comments in these proceedings, cost cap proceedings could easily become impractically detailed and time-consuming in light of the complexity of utility ratemaking. The statute sets out a test that is inherently imprecise, where every element and sub-element of the comparison could be extensively litigated. Interminable proceedings and extensive uncertainty about each of those litigated points would undermine the Legislature's goal of limiting ratepayer impacts. To give meaning to the Legislature's direction, and recognizing that forecast costs are inherently imprecise, determining whether the cost cap has been reached will require an analysis markedly simpler than we undertake for rate setting. Only pragmatic, implementable rules that define the cost cap calculation, using simplifying assumptions that are truly tractable, can provide certainty and clarity for parties and balance the goals the Legislature tasked us with in a section 10 proceeding. We therefore direct the Administrative Hearings Division to open a rulemaking docket to define key elements of the evaluation and simplifying assumptions to be made. We briefly summarize here the key policy and legal determinations made in this order, as well as the issues to be addressed in the rulemaking.

A. Summary of Policy and Legal Determinations

1. We are meant to grant narrowly-tailored, duration-limited exemptions once costs to which the utility has committed are projected to exceed 6 percent of total annual revenue requirement (ARR) for a year. This is intended to pace the achievement of HB 2021's emissions reduction goals, setting an extended schedule as compared to the dates in the legislation, to maintain customer affordability.

2. This order does not change our approach to cost recovery, prudence, and resource procurement. Procurement decisions during an RFP or any other procurement process must remain holistically prudent or reasonable over the near and long term for customers. HB 2021 compliance is one element of overall affordability, reliability, and customer risk mitigation in the near

and long term and utilities should continue to optimize procurement holistically, consistent with our longstanding expectation.

3. HB 2021 compliance must be a significant purpose of a cost or investment to qualify for inclusion in the cost cap. Where there are multiple drivers for a cost or investment, we will estimate a reasonable proportion to allocate to the HB 2021 cost cap.

4. While a determination that an investment or cost contributes to compliance is final under the statute, determinations as to the projected rate impact of such investments and costs may be updated in future section 10 proceedings if new information is available.

    a. Where the section 10 inquiry involves a cost or investment allocated among multiple states, the percentage of the cost attributed to Oregon is an aspect of the cost's rate impact and is thus subject to update.

    b. If an investment has multiple drivers and thus only a percentage is attributed to HB 2021 compliance, that attribution will not be revisited in future section 10 proceedings.

5. An exemption that has been granted with respect to a given compliance year is final, regardless of new information pertaining to that year. Given the long lead time necessary to come into compliance with HB 2021's targets, an exemption from compliance that could be revoked at any time prior to, or even during, the year at issue would be no exemption at all.

6. As a first step in determining whether proposed actions contribute to HB 2021 compliance and what cost(s) or investment(s), if any, those actions are displacing in rates, the utility must submit in the section 10 proceeding a counterfactual portfolio analysis that leaves in place all constraints and assumptions used in development of the preferred portfolio of the utility's most recent IRP, with the exception of those constraints and assumptions required to ensure compliance with sections 1-15 of HB 2021.

a. While a counterfactual analysis filed and supported in a section 10 proceeding will be presumptively reasonable, the utility's analysis will not be dispositive; it may be rebutted with persuasive evidence that yields a material change in the result.

7. A utility commitment to a cost or investment (e.g., an executed contract) is sufficient to qualify as "forecasted costs" under the statute.

   a. While some determinations in a section 10 proceeding—the rate impact of an action and whether the cost cap has been breached as a result—cannot be made until a utility has committed to the action, a section 10 proceeding may be initiated before that point, so that, for example, we can consider the threshold question of whether a proposed action is "for the purpose of" HB 2021 compliance while the utility's RFP is underway.

8. Forecasted and actual HB 2021 compliance costs must be netted against any costs or investments avoided to determine whether the costs caused by HB 2021 compliance exceed 6 percent of the total ARR for a given year. This estimate of avoided costs or investments should be based on the same underlying assumptions as the forecasted HB 2021 cost, preferably drawn from the same counterfactual analysis. Such estimates will be necessarily imprecise.

9. Similarly, any revenue earned by an investment, through for example sales of excess energy or power market arbitrage opportunities, that would defray customer rate impacts should also be netted against the cost of the investment.

10. The forecasted costs for a given year must be compared against the projected ARR for that year, rather than against the ARR for the year in which the analysis is performed. The rulemaking should build on the anticipated use of multi-year rate plans to simplify the future ARR estimate.

11. Where HB 2021 compliance is a major driver of a cost or investment, but the cost or investment also contributes to RPS compliance, the cost of renewable energy certificates (RECs), whether actual or imputed, is attributable to the RPS cost cap, not the HB 2021 cost cap.

12. The cost cap applies only in individual years, based on the relevant costs projected in a single year as a percentage of that same year's projected revenue requirement. Narrowly tailored and duration-limited exemptions may be set out for a number of years in a single section 10 proceeding, based on a year-by-year review of each individual year's costs and ARR. The cost cap is intended to create a glide path, pacing investment to limit costs in excess of roughly 6 percent of ARR each year until ultimate compliance is achieved.

13. The multi-step compliance path described in the legislation and the long lead time required to achieve compliance means that any exemption may inherently create significant compliance hurdles at the next milestone year. The future implications of an individual year's exemption or the need for cascading exemptions beyond the duration-limited exemption set out in a section 10 proceeding must be addressed in future section 10 proceedings, when committed costs can be forecast.

B. Issues to be Addressed in the Rulemaking

1. To give functional meaning to the balance the Legislature instructed us to find, the rulemaking should prioritize establishing definitions and identifying appropriate simplifying assumptions so that a section 10 proceeding can be completed in a timely manner.

2. A high degree of precision is not practicable in these cases. Thus we decline to pursue further precision or continue to litigate issues that would not materially impact whether the six percent threshold is breached. We believe that the Legislature's goals can be best met with the development of simplifying assumptions with respect to each element of the calculation. We intend for the rules to focus on the elements that materially affect the final outcome.

a. For example, given the magnitude of power costs, such costs should be accounted for in the denominator and, if appropriate, in the numerator; however, power cost forecasts are imprecise and parties may have strongly differing views on appropriate assumptions about the future. The rulemaking should adopt simplifying assumptions to allow for a consistent methodology that recognizes the inherent imprecision without unduly impairing accuracy or relevance.

3. The rulemaking should define or clarify the sources of inputs to the cost cap test that will be relied upon, which may include determinations made in other contested cases. While some flexibility in the sources of information for the test is necessary to adapt to unanticipated future situations, section 10 proceedings will be intractable if the source of every element of the test must also be adjudicated in each section 10 proceeding. The rules should set out key sources for the most material costs and the essential analytical approach.

4. If the final rules adopted in docket AR 669 require utilities subject to HB 2021 to include a counterfactual portfolio analysis in their IRPs, this rulemaking should address the potential for the utility to update and revise the IRP counterfactual analysis, for example through prefiling stakeholder workshops, before submitting it in a section 10 proceeding. Such updates and revisions should be limited to changes and corrections that are more likely than not to meaningfully affect the elements used in the section 10 proceedings.

5. The rulemaking should consider the impact of any potentially relevant legislation adopted since the passage of HB 2021, such as HB 3546 (2025) and HB 3179 (2025), including, as noted above, the impact of multi-year rate plans on projections of annual revenue requirements.

III. DISCUSSION

We first clarify threshold legal questions. We then address certain procedural issues raised by the parties' briefs and comments, and divide our remaining discussion by the four sets of questions laid out in Order No. 24-002.

A. Questions of Law

1. Positions of the Parties

The Administrative Law Judge asked the parties to address in reply comments the question: "Does ORS 469A.445 call for the Commission to issue an exemption that prevents a utility's projected obligatory compliance costs from reaching 6 [percent] 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 [percent] of its projected revenue requirement for that year?"[3]

According to AWEC, if customers bear any costs above the six percent cost cap, the "customer protection intended by the Legislature" is "nullif[ied]."[4]

PacifiCorp, RNW/NWEC, and NewSun argue that ORS 469A.445 calls for the Commission to issue an exemption if actual or projected compliance costs have reached or exceeded 6 percent of the utility's projected revenue requirement for a given year.[5]

GEI urges that the "actual or anticipated cumulative rate impact" clause in ORS 469A.445(4) should be interpreted to impose the highest bar supported by the language, which GEI states is an interpretation that an exemption be granted if costs have exceeded 6 percent of the projected revenue requirement for a year.[6]

PGE "does not believe ORS 469A.445 calls for the Commission to issue an exemption that 'prevents' compliance costs from reaching 6 [percent]," but also "believes that statute does not necessarily restrict exemption from compliance until 'projected' compliance costs have reached or exceeded the 6 [percent] threshold."[7]

Separately, the utilities express significant concerns regarding the implications of section 10 proceedings for cost recovery and cost allocation.[8]

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[3] Memorandum at 1 (Sept. 2, 2025).
[4] AWEC Reply Comments at 2 (Sept. 29, 2025).
[5] NWEC/RNW Reply Comments at 2 (Sept. 29, 2025); PacifiCorp Reply Comments at 3 (Sept. 29, 2025); NewSun Reply Comments at 3-5 (Sept. 29, 2025).
[6] GEI Reply Comments at 1 (Sept. 29, 2025).
[7] PGE Reply Comments at 6 (Sept. 29, 2025).
[8] *See*, *e.g.*, PGE Opening Comments at 9 (Aug. 12, 2025); PGE Reply Comments at 7-8 (Sept. 29, 2025); PacifiCorp Reply Comments at 11-14 (Sept. 29, 2025).

2. Resolution

a. Timing of exemption

We find that we are meant to grant narrowly tailored, duration-limited exemptions once actual and forecasted costs exceed 6 percent of total projected ARR for a year. This implies pacing the achievement of HB 2021's emissions reduction goal if necessary to maintain customer affordability.

The plain language of the statute states that we are to grant an exemption from "*further* compliance" if we determine "that the actual or anticipated cumulative rate impact calculated under subsection (3) of this section *exceeds* six percent of the annual revenue requirement for a year."[9] In other words, we cannot relieve a utility of the obligation to commit to the marginal action that would have caused its compliance costs for a given year to exceed 6 percent; instead, an exemption relieves the utility of the obligation to incur *further* costs beyond the marginal action. Section 10's heading—"*Cost cap* for electric companies; determining compliance costs and rate impact; exemption" (emphasis added)—has likely contributed to the divergence of views on this subject. But as laid out in the statute's text, six percent is not a true "cap" on costs, but rather a threshold that, once passed, triggers a limited-duration exemption from further compliance.[10] That we are not permitted to grant an exemption under section 10 until projected costs for a year exceed six percent of that year's projected revenue requirement does not, as AWEC would have it, "nullify" section 10's consumer-protection purpose;[11] to the contrary, we are implementing the statutory protection as crafted by the Legislature.

We note, however, that because section 10 proceedings will require us to consider projected costs and revenue requirements, they will involve significant forecast uncertainty. Accordingly, if we find it more likely than not that the six percent threshold will be met, we consider that to meet the statutory standard requiring us to grant an exemption.

b. Effect of Commission determinations and acceptance of analysis

ORS 469A.445(5) provides that "[a] determination by the commission made under this section shall have no effect on and may not be used as collateral or presumptive evidence

[9] ORS 469A.445(4).
[10] *See* ORS 174.540 ("Title heads, chapter heads, division heads, section and subsection heads or titles and explanatory notes * * * do not constitute any part of the law").
[11] AWEC Reply Comments at 2 (Sept. 29, 2025).

in any other proceeding that determines rate recovery of the investment or cost, including in a general rate case or in a proceeding under ORS 469A.120." In other words, determinations as to (1) whether a cost or investment is for the purpose of compliance with HB 2021, (2) the actual or anticipated rate impact of a cost or investment, and (3) whether the 6 percent cost cap has been exceeded for a given year, will not carry evidentiary weight in a cost recovery proceeding.[12]

B. Section 10 Procedural issues

1. *Positions of the Parties*

CUB notes that "[t]here 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."[13]

Several parties describe section 10's procedural requirements as consistent with a contested case.[14] PGE recognizes that section 10 requires that parties be provided procedural rights, but argues that "all parties [would] benefit from streamlining this process as much as possible," claiming that "[t]here is already a robust discovery and comment period for IRPs."[15] PacifiCorp urges us to deal with section 10 petitions on an expedited basis, suggesting a fast-track process that would render a decision within 90 to 120 days, on the basis that "ORS 469A.445(2)(a) does not preclude such an expedited process, as it does not specify minimum durations or procedural timelines that would prevent one."[16] According to PacifiCorp, "[t]he 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."[17] PacifiCorp also suggests that "[t]he cumulative rate impact associated with Commission-designated compliance resources could be evaluated as part of existing rate proceedings, such as a transition adjustment mechanism [(TAM)]or renewable adjustment clause [(RAC)] filing," arguing that "[t]he requirement that the Commission's compliance waivers be limited in duration

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[12] That an exemption is in place with respect to a particular year would be a fact, not a determination. While that fact could be relevant evidence in a cost recovery context, it would not be dispositive.
[13] CUB Reply Comments at 2 (Sept. 29, 2025).
[14] *See*, *e.g.*, PacifiCorp Reply Comments at 15 n.36 (Sept. 29, 2025); CUB Reply Comments at 2 (Sept. 29, 2025); GEI Reply Comments at 2 (Sept. 29, 2025); NewSun Reply Comments at 1 (Sept. 29, 2025).
[15] PGE Comments on Draft Order at 5 (Aug. 12, 2025).
[16] PacifiCorp Opening Comments at 4 (Aug. 12, 2025).
[17] PacifiCorp Reply Comments at 4 (Sept. 29, 2025).

is reasonably aligned with the one year forward scope of these proceedings, both of which are already contested cases."[18]

In recognition of proposals in the initial comments to initiate section 10 proceedings at various points in the planning and procurement process, the Administrative Law Judge asked the parties in their reply comments to "provide an illustrative timeline for how an IRP/CEP, RFP, and section 10 proceeding would best align."[19] AWEC's timeline submitted in response calls for the Commission to initiate a section 10 investigation two weeks after the utility submits its IRP/CEP, to be followed six weeks later by simultaneous opening testimony, with another month for reply testimony, and fifteen day intervals between reply testimony, hearing, opening briefs, and closing briefs. PacifiCorp submitted a timeline in which the utility would file a section 10 petition contemporaneous with RFP issuance, to be updated when the utility requests approval of the final short list (FSL). The Commission would then issue a section 10 determination at the same time as acknowledgment or non-acknowledgment of the FSL, "within 60-90 days from" the filing of the update.

2. Resolution

As discussed further below, a section 10 inquiry must make three determinations:[20] First, which costs or investments raised by the petitioner contribute to compliance with sections 1-15 of HB 2021? If costs or investments are fully or partially identified as contributing to compliance, we must then determine the annual net impact on rates for each year under consideration. To make this determination, we must first estimate, for each year under consideration, the gross annual rate impact of the cost-cap-eligible cost or investment and the annual rate impact of any cost or investment being displaced, as well as any revenue projected to be earned by an investment that would defray customer rate impacts, such as through sales of excess energy or power market arbitrage opportunities. Finally, we must determine whether the cumulative net impact on rates for a given year of cost-cap-eligible costs and investments exceeds six percent of that year's total revenue requirement—requiring us first to estimate the total annual revenue requirement for the year under consideration.

ORS 469A.445(2)(a) requires that we "provide parties to the proceeding with the procedural rights described in ORS 756.500 to 756.610, including the opportunity to develop an evidentiary record, conduct discovery, introduce evidence, conduct cross-examination and submit written briefs and oral arguments." These statutory requirements

[18] PacifiCorp Reply Comments at 7 (Sept. 29, 2025).
[19] Memorandum at 2 (Sept. 2, 2025).
[20] As noted above, such determinations would not be relevant evidence in a cost recovery case.

meet the definition of a contested case under the Oregon Administrative Procedures Act.[21] The Administrative Hearings Division will establish the appropriate process when a section 10 petition is filed.

We cannot displace parts of the section 10 process into IRP and RFP proceedings, which are other-than-contested and thus lack the procedural protections to which section 10 entitles parties. And for administrative reasons, we believe it will generally be more effective for section 10 determinations to be made in the context of a standalone section 10 proceeding. The rulemaking should, however, define or clarify guidance for the sources of inputs to the cost cap calculation, which may include determinations made in other contested proceedings; for example, while "[t]he cumulative rate impact associated with Commission-designated compliance resources"[22] would be determined in a section 10 proceeding, the outcome of a TAM or RAC proceeding may be relevant to that determination.

In light of the statutorily required process, as well as the likely complexity of the issues, the highly expedited procedural schedules proposed by AWEC and PacifiCorp do not appear to be realistic. For example, while PacifiCorp's illustrative procedural schedule does not indicate its proposed timing for testimony, a hearing, and briefs, it appears that at minimum one round of testimony, followed by the hearing, briefs, and Commission deliberations, would need to take place in the two to three months that PacifiCorp allows between the utility's "update[of the] [s]ection 10 proceeding with actual resource information and forecasted cost impacts of HB 2021 compliance" and the Commission's decision.[23] AWEC's proposed schedule calls for two rounds of testimony, a hearing, and two rounds of briefs (but not a Commission decision) to be completed within approximately four months.[24] To give full effect to the Legislature's intent, section 10 proceedings must be resolved reasonably quickly;[25] but attempting to compress a contested case proceeding into four months or less would go beyond the bounds of what is reasonable. We note, however, that parties to a section 10 proceeding may be able to narrow the scope of litigated issues, and thus facilitate a more prompt resolution, via stipulation.

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[21] ORS 183.310(2)(a).
[22] PacifiCorp Reply Comments at 6-7 (Sept. 29, 2025).
[23] PacifiCorp Reply Comments at 6 (Sept. 29, 2025).
[24] AWEC Reply Comments at 5-6 (Sept. 29, 2025).
[25] Contrary to PacifiCorp's assertion, however, our obligation is not to "exempt utilities from further compliance once six percent is exceeded"; it is to grant an exemption *once we have determined, following the statutorily required process*, that six percent has been exceeded. ORS 469A.445(4).

C. Investments and costs eligible for HB 2021 cost cap inclusion

Section 10 uses two different phrases to describe applicable investments and costs. Subsection (1) describes an investigation into investments made, costs incurred, or forecasted costs estimated "for the purpose of compliance." Everywhere else in section 10, the statute refers to whether an investment or cost "contributes to compliance." Did the Legislature intend to capture only those actions that the petitioner can prove the utility would not have taken, except to meet the requirements of HB 2021 or does section 10 capture a broader category of actions?

1. Draft Order

The draft order concluded that for an action to be eligible for inclusion in the section 10 cost cap, compliance with sections 1 through 15 of HB 2021 must be a significant purpose of the action. The draft order proposed to accept the Joint Utilities' suggestion of conducting "counterfactual" analyses, which would shed light on whether HB 2021 compliance was a significant purpose of an action, as well as on the action's net impact on the utility's revenue requirement. The draft order indicated that, because counterfactual portfolios would necessarily be high-level projections, they would be highly persuasive but not dispositive evidence that an action should not count towards the HB 2021 cost cap.

2. Positions of the Parties

There is broad agreement among the parties that where an investment or cost is the least cost, least risk option for serving load reliably, regardless of any policy requirements, that investment or cost should not be included in the HB 2021 cost cap. Opinions diverge, however, with respect to actions required by statutes other than HB 2021 or taken for a variety of reasons.

PacifiCorp and PGE (Joint Utilities) argue that the statute uses the phrase "contributes to compliance" because it was understood that some investments or costs may not be pursued only for compliance, and that a Commission investigation would be needed to determine what portion of the investment or cost contributed to compliance. The Joint Utilities propose three categories of utility actions: those that do not fall under the cost cap at all; those for which a portion could be included; and those that could be fully included in the cost cap because they are "for the purpose of" reducing greenhouse gas emissions. In the first, cost-cap-ineligible category they would place, for example, cost-effective energy efficiency and demand response.[26] Partially-includable investments and costs in the Joint Utilities' second category could include, among others, resources acquired or costs incurred to comply with the RPS, the small-scale renewable requirement under ORS 469A.210, or the net metering and community solar requirements of ORS 757.300 and 757.386.[27]

The Joint Utilities propose a two-step analysis in which we would first determine whether an investment or cost was incurred for the purpose of compliance,[28] suggesting that this could be accomplished by asking the utilities to model IRP portfolios as if HB 2021 did not exist; an investment or cost included in both the acknowledged IRP/CEP and this counterfactual portfolio would not be eligible for cost cap treatment because the utility would have proposed it anyway. If the cost or investment occurs only in the acknowledged IRP/CEP, then the Commission would proceed to step two, in which the proponent for including the investment or cost in the cost cap would have the opportunity to show that compliance is at least partly the reason for the investment, and the Commission would determine what portion or percentage of the investment or cost assists the utility in reducing emissions consistent with the targets even if required by a separate, underlying statutory requirement.

According to AWEC, any investment that brings the Joint Utilities closer to their emissions requirements under HB 2021 plays a significant part in their compliance efforts with that law; it does not matter whether the investment may also contribute to other statutory obligations, or even if the investment was pursued primarily for a different statutory obligation. While AWEC believes that costs incurred to meet reliability obligations should be excluded from the cost cap, the same is not true of costs to meet other legal requirements such as the RPS, the Public Utility Regulatory Policies Act, and ORS 469A.210: AWEC contends that each of these legal mandates shares a common purpose with HB 2021, i.e., carbon emissions reduction, and that therefore a purpose of the acquisition of resources to meet these other requirements is to achieve HB 2021 compliance, and the costs of these resources contribute to that compliance.[29]

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[26] The Joint Utilities argue that "[w]hile [demand response or energy efficiency] investments or costs could have an effect on reducing emissions, the foundation for these investments pre-date HB 2021, support traditional notions of resource planning, and would not be made 'for the purpose of' reducing emissions," and that "the Legislature would have known of the requirement to plan for and acquire EE and DR pursuant to either the former public purpose charge in ORS 757.612, or of the modified charge created through HB 3141 in the same legislative session that it adopted HB 2021." Joint Utilities Initial Brief at 4.
[27] Joint Utilities Opening Brief at 5 (July 24, 2025). Joint Utilities argue that it is reasonable to include such costs in the cost cap because "the fundamental reason for those statutory requirements relate to the same policies underpinning HB 2021: increase renewable energy generation or reduce emissions" and "these investments/costs will reduce emissions from baseline." *Id*. at 4-5.
[28] *Id*. at 6.
[29] AWEC Opening Brief at 6.

CUB, NewSun, and NWEC/RNW argue that the HB 2021 cost cap applies to costs and investments that would not have been incurred or forecasted but for HB 2021. CUB and NWEC/RNW would exclude from the cost cap any costs and investments incurred to comply with other legal mandates such as the RPS, because such investments would have occurred without HB 2021. NewSun agrees that projects undertaken for compliance with regulatory requirements should not be included in the cost cap, and includes in that category compliance with the Western Resource Adequacy Program (WRAP). CUB notes, however, that the incremental costs of expanding existing programs such as community solar or energy efficiency for the specific purpose of HB 2021 compliance can be considered for cost cap purposes.

In response to the draft order, NWEC/RNW state that they "understand the Commission's position that the 'major driver' test bridges the gap between the statutory phrases 'for the purpose of compliance' and 'contributes to compliance,' and * * * support the Commission's effort to retain more discretion than a pure 'but for' test would encompass."[30] They urge us to treat the counterfactual analysis as "persuasive" rather than "highly persuasive" evidence.[31] CUB raises concerns regarding the potential for significant compliance cost impacts that would not be captured by the counterfactual.[32]

PGE notes in its comments on the draft order that the draft order does not contemplate how to account for past investment decisions. PGE argues that there needs to be a clearer framework for applying the draft order's proposed standard—that compliance must be a significant purpose of the action—to costs that have already been incurred, noting that "the process to determine what past investments were made with HB 2021 being a significant purpose would be imprecise," and requesting that "utilities be provided an opportunity to propose a method on how to account for these previously incurred costs for discussion in this docket."[33]

GEI argues that "[t]he process of determining whether to exempt a regulated entity from a legal obligation should not be easy. * * * [T]he PUC should make it * * * clear that a high level of detail about the 'investments or costs' is required from an electric company or ratepayer advocate seeking an accounting under [s]ection 10 to demonstrate that the costs have exceeded the 6[percent] threshold."[34]

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[30] NWEC/RNW Opening Comments at 3 (Aug. 12, 2025).
[31] *Id.* at 5 (Aug. 12, 2025).
[32] CUB Reply at 2-4 (Sept. 9, 2025).
[33] PGE Comments on Draft Order at 8-9 (Aug. 12, 2025).
[34] GEI Reply Comments at 2 (Sept. 29, 2025).

3. Resolution

As the parties acknowledge, in order to answer the question of what investments or costs qualify for inclusion in the cost cap, we must interpret the phrases "for the purpose of compliance with ORS 469A.400 to 469A.475"[35] and "contribute to compliance with ORS 469A.400 to 469A.475."[36] We recognize that a pure "but-for" test—i.e., an approach that would include actions in the cost cap only if HB 2021 compliance is the sole motivation—is impractical and would render the cost cap meaningless, given the multiple drivers behind almost any utility decision. An interpretation that ignores the rate impact of actions whose primary purpose is HB 2021 compliance because other factors also weighed in favor of the action would be inconsistent with the clear intent of the cost cap. But AWEC's proposed approach, in which any utility action that reduces greenhouse gas emissions would count toward the cost cap, goes too far in the opposite direction: if a utility's costs of complying with a host of other obligations exceeded the HB 2021 cost cap, the utility would be exempted from compliance with sections 1 through 15 of HB 2021 without ever having taken an action "for the purpose of" compliance with those sections. Such an expansive interpretation of cost cap eligibility would be inconsistent with the intent expressed in ORS 469A.445(4) to limit the scope and duration—and thus the negative environmental impacts—of exemptions. It would also ignore the cost cap's explicit limitation to sections 1 through 15 of HB 2021.

To chart a path between these two extremes, we find that for an action to be eligible for inclusion in the section 10 cost cap, compliance with sections 1 through 15 of HB 2021 must be a significant purpose of the action. We are sensitive to the rate impacts of HB 2021 as a whole, and of other statutory requirements. But the Legislature did not choose to include in the cost cap all of HB 2021's requirements, let alone other obligations. If compliance with sections 1 through 15 of HB 2021 is not among the major drivers behind a cost or investment, we determine the legislative intent to be that the cost or investment does not count toward the cost cap. Where HB 2021 compliance is 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, we will consider the appropriate portion of the cost or investment for inclusion in the cost cap.[37] In this way, we can give full effect to the statute's limitation of our cost cap proceedings to "accounting for investments made, costs incurred or forecasted costs estimated by the

[35] ORS 469A.445(1).
[36] *Id.*; ORS 469A.445(2)(b); ORS 469A.445(3).
[37] The drivers of a project can also be considered a project's co-benefits. Nearly any project or program will bring co-benefits to ratepayers and a prudent investment may well bring more benefits than costs. However, offsetting the cost of an investment by its many benefits, as NewSun suggests, would go too far. We aim to estimate a proportional allocation of an investment's costs across drivers.

electric company *for the purpose of compliance* with ORS 469A.400 to 469A.475,"[38] while also allowing for such proceedings to include in the cost cap costs or investments that "contribute to compliance" with HB 2021,[39] even if HB 2021 compliance was not the *sole* motivation behind the utility action.

A determination that an investment or cost contributes to compliance is final at the Commission.[40] If an investment has multiple drivers and thus only a percentage is attributed to HB 2021 compliance, that allocation will not be revisited in future section 10 proceedings. However, determinations as to the projected rate impact of such investments and costs may be updated in future section 10 proceedings in light of new information. Where multi-state cost allocation is in play, the percentage of the cost attributed to Oregon is an aspect of the cost's rate impact, not whether or how much the cost or investment contributes to compliance, and is thus subject to update.

Section 10 contemplates assessments of particular investments and costs, not a whole-portfolio approach. HB 2021 compliance requirements functionally touch on every aspect of the utilities' operations – from generators to transmission to distribution system investments to resource bidding strategies and load flexibility. As a result, these investments and costs will be found not only in large-scale generation procurement through RFPs, but also in proceedings related to power costs, general rate cases and other cost recovery proceedings. We agree with the Joint Utilities, however, that comparison of a utility's acknowledged IRP/CEP against a "counterfactual" portfolio developed as if HB 2021 did not exist[41] will be a crucial first step in the analysis to determine which costs or investments should be examined more closely. This approach will also provide information for stakeholders regarding the counterfactual cost or investment to which a putative HB 2021 cost or investment should be compared, as well as providing advance warning to the Commission and stakeholders that a utility may be approaching the six percent cost cap threshold. We therefore accept the Joint Utilities' offer to model IRP portfolios as if HB 2021 did not exist, with one modification: Because the cost cap applies only to costs associated with sections 1 through 15 of HB 2021, the "counterfactual" model should remove only the constraints and assumptions required to ensure compliance with those sections, leaving in place all other constraints and assumptions (including those associated with the requirements of sections 16 through 40 of HB 2021) used in development of the preferred portfolio. This analysis will help to identify the most material generation portfolio choices, including distributed procurement and load flexibility, as well as implicated transmission. Because our IRP guidelines

[38] ORS 469A.445(1) (emphasis added).
[39] *Id*.
[40] ORS 469A.445(2)(d).
[41] Joint Utilities Opening Brief at 6 (July 24, 2025).

require the inclusion of demand side, load-based, and small-scale generation solutions, a counterfactual analysis remains an effective starting place to determine how much an investment is driven by HB 2021 goals as compared to other drivers. A utility whose costs and investments are the subject of a section 10 request should submit such a counterfactual analysis in those proceedings.

These counterfactual portfolios, like the IRP, are necessarily high-level projections. As a result, inclusion of an action in the counterfactual portfolio, while highly persuasive and presumptively reasonable, would not be dispositive evidence that the action should not count toward the HB 2021 cost cap. Nor would an action's absence from the counterfactual be dispositive evidence that the action is wholly "for the purpose of" HB 2021 compliance. The utility's development of a counterfactual analysis will not be a purely mechanical exercise; there is room for judgment calls and thus potentially room for principled disagreements. The utility's counterfactual analysis may be rebutted with persuasive evidence that yields a material change in the result. And, recognizing that HB 2021 fundamentally changes the landscape with respect to factors such as avoided cost, other evidence of drivers, such as a proxy avoided cost based on an emitting resource, may also be appropriate points of comparison. Transparency of inputs, assumptions, and modeling results will be vital. The section 10 contested case process should enable such transparency; we support in addition (but do not mandate) PacifiCorp's proposal regarding pre-filing stakeholder workshops.

On the related question of whether this approach should be applied to the total investment or cost or just to the incremental cost, we find that although section 10, unlike the RPS cost cap set forth at ORS 469A.100 does not explicitly refer to "incremental" costs, it is not possible to determine the "actual or anticipated rate impact for the investment or cost"[42] without reference to the cost of the non-HB 2021-compliant alternative that would otherwise have been included in rates. Subsection 3(a) also directs us to calculate cumulative costs "as adjusted by any change in *net* costs expected or foreseeable at the time of inclusion."[43] In other words, if we determine that an investment or cost contributes to compliance with ORS 469A.400 to 469A.475, we must also determine what investment or cost it is displacing on a going forward basis – whether those investments or costs are being retired from the revenue requirement or were avoided altogether – as well as the rate impact of any such displaced investment or cost. We are meant to include in the cost cap calculation only the difference.[44] For example, if a utility

[42] ORS 469A.445(3).
[43] ORS 469A.445(3)(a) (emphasis added).
[44] Determining the cost or investment being displaced will require a case-specific analysis; for example, we recognize that the value of a resource to a utility depends on many factors in addition to its nameplate capacity or effective load carrying capacity. This analysis of the cost of an alternative is also distinct from estimating the benefits of an investment.

is procuring energy efficiency beyond what would be cost effective in a non-HB 2021 world, and that additional energy efficiency procurement is found to be for the purpose of HB 2021 compliance, we would need to determine, for each year being studied, the rate impact of the costs the utility will avoid as a result of the additional energy efficiency (e.g., fuel costs), and subtract that amount from the rate impact of the additional energy efficiency in that year to determine the net impact on rates. Similarly, because a section 10 inquiry is fundamentally an evaluation of customer rate impact, any revenue earned by an investment that would defray customer rate impacts, for example through sales of excess energy or power market arbitrage opportunities, should also be netted against the cost of the investment.

We understand that a full counterfactual analysis as described above may be less feasible with respect to past resource decisions. However, because the cost cap applies to cumulative compliance costs, it is nevertheless necessary to determine which such actions contribute to HB 2021 compliance, as well as the incremental costs of any past actions that we determine should be included in the cost cap analysis. As noted above, inputs to the second determination include both the gross rate impact of the cost or investment at issue and the rate impact of any cost or investment being displaced. These will necessarily be estimates as precision will be impossible to achieve. In light of this reality, again simplifying assumptions that focus parties' attention on the most material costs are crucial. The issue of what evidence and analysis could be appropriate with respect to costs that have already been incurred should be addressed in the rulemaking, which will provide a forum for PGE's request that the utilities—as well as other stakeholders—be provided an opportunity to propose a method on how to account for such costs.

D. Forecasted costs

> Section 10 contemplates the Commission consider not only investments made and costs incurred but also "forecasted costs estimated by the electric company." Does the inclusion of "forecasted costs" mean estimated future costs associated with an action the utility has already taken? Or should section 10 be interpreted also to encompass anticipated actions and their anticipated costs (i.e., actions acknowledged in an IRP, CEP, or RFP but not yet taken) and, if so, how much certainty should be required to recognize a cost under [s]ection 10?

1. Forecasted HB 2021 compliance costs

c. Draft Order

The draft order proposed that we consider a utility commitment to a project as sufficient to meet the definition of "forecasted costs" as used in the statute, and that costs and investments that are not yet being recovered in rates must be compared against the projected total annual revenue requirement for the years in which they are expected to impact rates.

d. Positions of the Parties

Joint Utilities state that HB 2021's "drafters wanted to allow for the investigation of costs from anticipated actions, while at the same time allow for retroactive adjustments once actual costs were known. This method would also provide certainty to the regulated community. For example, in advance of deploying significant capital, stakeholders could initiate investigations on particular investments or compliance strategies to inform cost cap implications of the strategy, or whether the Commission agreed that the action was relevant to the cost cap at all."[45] Joint Utilities therefore argue that "costs should include estimated future costs to the extent that those future costs would affect rates * * *, as well as anticipated actions and their costs (e.g. actions acknowledged in an IRP that were relatively certain to be accomplished, but not yet taken)."[46] The Joint Utilities suggest that "mere IRP acknowledgement should not be sufficient to trigger an investigation. A higher standard of certainty should be required, for example, a project that has been determined to be on a short-list in an RFP. For projects acquired outside of an RFP * * *, a utility could determine the likely certainty of the project before asking to open an investigation and would, regardless, bear the burden of showing that the cost would likely contribute to compliance."[47] The Joint Utilities add that "[a] retail electricity provider is not prohibited from making an investment that would cause the entity to exceed the cap – the cap only exempts the provider from further compliance and does not prohibit the investment. Moreover, the cost cap treatment cannot be used as evidence in any proceeding determining actual rate recovery by operation of ORS 469A.445 (5)."[48]
AWEC recommends that section 10 be interpreted to encompass a utility's anticipated actions and costs, not just forecasted costs of actions already taken. AWEC argues that if the cost cap includes only costs a utility has already incurred, and the utility reaches the cost cap, then "[e]ither customers will bear any costs above the six percent cost cap,

[45] Joint Utilities Opening Brief at 7 (May 23, 2024).
[46] *Id.*
[47] *Id.*
[48] *Id*. at 7 n.21.

thereby nullifying the customer protection intended by the Legislature, or the utility would bear the cost of exceeding the cost cap, thereby failing to recover the full prudently incurred cost of the resource."[49] And AWEC notes that we recently "set forth an expectation that resource planning 'must include greater attention to near-term management of costs and rate pressures.'"[50] AWEC suggests that "in a subsequent proceeding to finally determine if the cost cap is reached, the Commission could use the cost data assumed by the utilities in their IRPs and CEPs as the data on which the Commission would evaluate whether the HB 2021 cost cap is triggered based on a utility's action plan"[51] although AWEC acknowledges that "the actual costs a utility would incur to meet its action plan may differ materially from its IRP assumptions."[52] AWEC suggests in the alternative that we make a preliminary cost cap determination in the context of an acknowledgement order in an IRP/CEP proceeding, "subject to better information on likely actual costs the utility would incur"[53] such as determining the cost of resources that contribute to compliance with HB 2021 based on the final short list of bids the utility receives. AWEC notes, however, that "RFP bids are time-limited (as may be the utility's resource need)."[54] AWEC adds that even if we determine that IRP costs should not be considered in a cost cap investigation, "the IRP should have a role in at least providing a preliminary indication of whether a utility is likely to exceed the cap if it follows through on its action plan. Such a finding will put parties on notice that the cost cap may be exceeded based on the utility's actions, which will in turn create more certainty for parties when a cost cap investigation is initiated."[55]

CUB argues that section 10 provides that "a utility's *costs and investments incurred* to meet HB 2021's goals are subject to the bill's costs cap, as are also the *forecasted costs* estimated by the electric company for the purpose of compliance," adding that "[f]orecasted capital investments do not raise rates until they are used and useful, so it would be difficult to conclude that they have contributed to violating the six percent cost cap."[56] CUB points out that "IRPs are plans built on forecasted costs. IRP analyses do not provide anticipated rate impact of each investment. Rather, they compare net present value revenue requirement for the life of a project, but do not provide a year-by-year projection of 'rate impact.' This means that additional analysis is needed beyond what is supplied in an IRP for the purposes of HB 2021 compliance"[57] According to CUB, "[w]hile forecasted costs are uncertain, and arguably some are difficult to predict, the

[49] AWEC Opening Brief at 8 (May 23, 2024).
[50] *Id.* at 8, *quoting* LC 80 Order No. 24-096, at 22 (Apr. 18, 2024).
[51] AWEC Opening Brief at 8 (May 23, 2024).
[52] *Id.* at 9.
[53] *Id.*
[54] *Id.*
[55] AWEC Response Brief at 9 (June 20, 2024).
[56] CUB Opening Brief at 16 (May 23, 2025) (emphasis in original).
[57] *Id.* at 18.

Commission already considers forecasted costs in its decision-making, and they are distinguishable from speculative future costs which are not included in rates. And the plain language of the statute shows the legislature intended forecasted costs to be considered in a Commission cost cap investigation."[58]

NWEC/RNW argue that the cost cap should apply "only to identifiable costs associated with utility investments capable of being recovered in rates via a general rate case or the application of Oregon's renewable automatic adjustment clause, not hypothetical costs projected earlier in the planning and procurement process."[59] NWEC/RNW add that "[i]n a standard general rate case, Oregon uses an embedded cost approach, meaning that utilities and regulators begin with historical costs and then *forecast* those costs into a future test year. A utility's actual costs may then fluctuate, but what the utility actually recovers in rates are those costs that were forecasted based on a historical test year and then carried forward to a future test year. * * * Notably, speculative costs such as proxy resources identified to an IRP preferred portfolio and even shortlisted resources in an RFP are not forecasted into customer rates – only actual, identifiable costs."[60] NWEC/RNW note that "[n]ot only do IRPs bear no direct relationship to customer rates, but they are also based on broadly characterized needs to be met by proxy resources, which themselves may bear little relationship to the resources actually procured by a utility."[61]

In response to the draft order, PacifiCorp expresses concern that requiring a utility commitment to an action before considering that action for inclusion in the cost cap analysis "can render the cost cap meaningless" because costs could go up by more than 6 percent in years for which an exemption had been granted.[62] According to PacifiCorp, "waiting until a utility commitment can actually negate the need for a section 10 filing altogether and potentially, and unnecessarily, lead to increased emissions."[63] PacifiCorp states that it is unclear why a utility would need to make a section 10 filing for a project to which it had already committed, arguing that "if a project is being built and the utility has committed to pay costs, HB 2021 targets would be met and there is no reason for the utility to seek relief under section 10."[64]

[58] CUB Opening Brief at 19; *see also id.*at 17 ("Oregon uses future test years for ratemaking. The Commission starts with historic costs, and then adjusts them for known and measurable changes, including forward-looking costs. Speculative future costs are not included in rates, but actual forecasted costs are").
[59] NWEC/RNW Opening Brief at 9 (May 23, 2025).
[60] *Id.* at 11.
[61] NWEC/RNW Opening Brief a t 11 (May 23, 2025).
[62] PacifiCorp Opening Comments at 8 (Aug. 12, 2025).
[63] *Id.*at 8.
[64] *Id*. 3.

AWEC claims that the uncertainty inherent in the costs forecast in an IRP or CEP is not cause for concern, positing that "the Commission's application of the cost cap does not need to be perfect, it just needs to be defensible."[65] NWEC/RNW, however, argue that while "[e]xecution of one contract could theoretically provide a basis for triggering the cost cap and precluding execution of additional contracts[,] * * * before any contract has been executed any resource decisions are too speculative to support a [s]ection 10 filing."[66]

PGE advocates a "middle ground" that it says is "flexible and responsive to specific circumstances," pointing out that an "exemption" from compliance is not a "prevention" from compliance, and arguing that allowing a determination under the statute of an "anticipated" rate impact at the FSL stage of an RFP allows for a flexible and nuanced discussion in a section 10 investigation that can in part occur during an RFP FSL period.[67]

2. Resolution

The parties' arguments demonstrate the tension embedded in this question. There is a desire for early information in order to manage cost impacts, holding them as close to the six percent cost cap as possible. Procedural, practical and statutory realities limit how early or how quickly we can actually implement a pause on compliance to address cost pressures and slow the pace of investments.

A pause in compliance obligations can only come at the end of a section 10 cost cap proceeding. It cannot be provided in the midst of an IRP proceeding, even if the lowest-cost resource portfolio that achieves compliance appears likely to breach the cost cap. As discussed above and highlighted by parties, the IRP and CEP can provide information – and create the crucial opportunity for insight into the emissions and cost associated with a counter-factual, non-compliant future – but the IRP and CEP processes cannot relieve a utility of its compliance obligation.

Pragmatic considerations lend additional support to our conclusion: At the IRP stage, the generic projections available to us are insufficient to support any part of a cost cap evaluation. And while costs and resources at the RFP shortlist stage are known, though with some remaining uncertainty as projects may withdraw, the timing of the RFP process does not allow for a full section 10 proceeding to be conducted in parallel; as noted above, the procedural schedules suggested by PacifiCorp and AWEC cannot

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[65] AWEC Opening Comments at 6 (Aug. 12, 2025).
[66] NWEC/RNW Opening Comments at 7-8 (Aug. 12, 2025).
[67] PGE Reply Comments at 6-7 (Sept. 29, 2025).

reasonably accommodate the statutorily required process. It would, moreover, be difficult, if not impossible, for a stakeholder to mount such a challenge to a shortlisted resource given the limited information available at the RFP FSL stage. It may in some cases be reasonable, however, to initiate a section 10 proceeding before complete information is available regarding the rate impact of a particular action, so that, for example, we could consider the threshold question of whether a proposed action is "for the purpose of" HB 2021 compliance while the utility's RFP is underway.[68]

We recognize the possibility that only the utilities themselves will have the information necessary to support a section 10 request before a rate filing has been made. If a utility believes that a cost or investment qualifies for the cost cap, we encourage it to make a section 10 filing promptly. Like any decision under section 10, a Commission determination that a future project to which a utility has committed qualifies for inclusion in the HB 2021 cost cap has no bearing on the prudency determination that we will make at the time the utility proposes to include the project in rates.

Because years may elapse between a utility decision to commit to a project and when that project is recovered in rates, a narrow interpretation of "investments made, costs incurred or forecasted costs estimated by the electric company" that denied final section 10 evaluation of investments until a project was used and useful would create a substantial lag in determining whether the cost cap has been breached and compliance should be paused. During that lag, the utility would be required to continue towards compliance, committing to yet more actions that may qualify for the rate impact analysis. Such a long delay in action on the cost cap seems to render the cost cap meaningless. Thus, we will consider a utility commitment to a project (e.g., execution of a contract) as sufficient to meet the definition of "forecasted costs,"[69] recognizing the imprecision of this approach.

While we believe that this approach is the most feasible available to us within the constraints of ORS 469A.445, we recognize that it is an imperfect solution. Contrary to AWEC's suggestion, it will not be possible for us to make a section 10 determination and exempt a utility from further compliance instantaneously, at the moment the utility's costs exceed six percent of its annual revenue requirement; some amount of lag is unavoidable even in cases where some portion of the proceedings can take place before the utility commits to a particular project. It is likely unavoidable that in the time between

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[68] We envision a process similar in broad terms to that used for the TAM, in which the proceeding begins before final numbers are available. *See* Docket No. UE 199, Order No. 09-274, at 3-5 (TAM Guidelines laying out PacifiCorp's Initial Filing, Rebuttal Update Filing, and Final Updates).

[69] CUB's dichotomy between "investments" and "costs" assumes that HB 2021's use of the word "costs" is intended to be synonymous with the ratemaking sense of "expenses." Both the dictionary definition and the Commission's common use of "costs" are broader than CUB's, and in particular, can include capital expenditures as well as expenses such as power purchase agreements.

a utility's signing of a contract that puts it over the six percent threshold and our determination that the threshold has been met, the utility will be continuing to incur additional costs to carry out its statutory obligation to make continual progress toward HB 2021's emissions reduction targets.

To mitigate this timing issue to the extent possible under the statute, we reiterate that the utilities can and are encouraged to submit section 10 filings as soon as they have the information available to do so, and add moreover that each utility should monitor the cumulative incremental rate impacts of its existing *and planned* cost-cap-eligible costs and investments vis-à-vis its projected annual revenue requirements,[70] and notify the Commission and stakeholders if the utility believes it is approaching the six percent cap for a particular year, even if the actions at issue involve planned costs and investments that are not yet certain.

We emphasize, however, that an indication that the utility may be approaching the cap for a particular year does not change the utility's compliance obligations; and, furthermore, that nothing in this order alters either our approach to, or the utility's obligations regarding, cost recovery, prudence, and resource procurement. Procurement decisions during an RFP or any other procurement process must remain holistically prudent or reasonable over the near and long term for customers. Parties in these proceedings have suggested that one reason for early awareness of the potential to breach the 6 percent cap is the opportunity to optimize project selection in an RFP to maximize emissions reductions while minimizing near term rate impacts. This approach is likely impractical but regardless, disregards the many ways a project may be the least cost, least risk procurement decision. The Commission has not typically prioritized optimization of one need (e.g. compliance with HB 2021 with minimized near term rate impacts) over the myriad other optimizations evaluated through prudence review (e.g. performance of a project in a variety of market and fuel cost scenarios, comparative price per megawatt of effective load carrying capability). Doing so would raise questions about intergenerational equity between near term ratepayers and future ratepayers. A utility approaching the cost cap should not necessarily prioritize achieving compliance under the cost cap over a holistic analysis of the customer impact of the procurement options before them. HB 2021 compliance is one element of overall affordability, reliability, and customer risk mitigation in the near and long term, and utilities should continue to optimize procurement holistically, consistent with our longstanding expectation.

[70] We recognize that the utility's calculations will necessarily be somewhat speculative because it will be attempting to predict the Commission's determinations with respect to cost cap eligibility of costs and investments as well as its future annual revenue requirements. These projections are not intended to bind the utility or the Commission in any way, but rather to provide advance warning to all affected entities that a utility may be approaching the cost cap.

3. Projected annual revenue requirements

e. Draft order

The draft order noted that costs and investments that are not yet being recovered in rates must be compared against the projected total annual revenue requirements for the years in which they are expected to impact rates, not the utility's currently-effective revenue requirement, and described the exercise of projecting future revenue requirements as both fact-intensive and unavoidably imprecise.

f. Positions of the Parties

According to PacifiCorp, the use of net present value revenue requirement (NPVRR) is not suited for a section 10 filing because it does not capture the depreciating rate base that is associated with an owned asset.[71] PacifiCorp recommends that forecasted revenue requirements be based upon the current authorized revenue requirement with adjustments made for the load forecast and known and measurable changes, stating that this approach is defensible and transparent for stakeholders.[72] PacifiCorp states that the methodology for estimating future annual revenue requirements should start with the methodology outlined in OAR 860-083-0200, but notes that this RPS revenue requirement forecast methodology would need to be modified into a longer forward-looking calculation. [73]

PGE cautions us against using a "plausible range of annual revenue requirement," as they state has been suggested in the AR 669 IRP/RFP modernization docket, stating that the range could be wide to account for various unknowns, and the low and high end of a projection could render different results in a cost cap proceeding.[74] PGE urges us to clarify that revenue requirement projections developed in a section 10 proceeding "are unrelated to and have no bearing on future ratemaking."[75]

PGE and PacifiCorp ask that utilities be provided an opportunity to collaborate and develop a clear methodology for forecasting the denominator of the cost cap.[76]

AWEC suggests that "[r]ather than engaging in a 'fact-intensive' analysis of what a utility's future revenue requirement may be that the Commission admits is 'unavoidably imprecise,'" we should escalate the utility's revenue requirement by an agreed-upon

[71] PacifiCorp Opening Comments at 9 (Aug. 12, 2025).
[72] *Id.* at 9.
[73] PacifiCorp Opening Comments at 9 (Aug. 12, 2025).
[74] PGE Opening Comments at 8 (Aug. 12, 2025).
[75] *Id.* at 8.
[76] PGE Opening Comments at 8 (Aug. 12, 2025), PacifiCorp Opening Comments at 9 (Aug. 12, 2025).

inflation factor. AWEC states that its approach would dramatically simplify this piece of the analysis and that there is no reason to believe it would be any more or less accurate than a "fact-intensive" forecast of revenue requirement.[77]

4. Resolution

Costs and investments that are expected to impact rates in future years must be compared against the projected total annual revenue requirements for those years, not the utility's currently-effective revenue requirement. Section 10 revenue requirement projections will necessarily be rough approximations made several years in advance of the year at issue. It is neither feasible nor desirable to develop each year's denominator in a section 10 proceeding with the same level of certainty and rigor that we expect in a rate case. We expect the rulemaking to address simplifying assumptions and methodological issues—including, as noted above, the impact of multi-year rate plans—for the calculation of the denominator as well as the numerator of the cost cap determination. The rulemaking will provide a forum for the utilities' request for an opportunity to propose a methodology for forecasting the denominator.

E. Interaction between HB 2021 and RPS cost caps

> HB 2021, section 10 does not address interactions with the cost cap in Oregon's RPS law. How should the HB 2021 cost cap be applied to investments and costs required to satisfy the RPS?

1. Draft Order

The draft order proposed that where a resource acquired for the purpose of HB 2021 compliance also brings the opportunity to procure the RECs needed to contribute to the utility's compliance with the RPS, the cost of RECs is applicable to the RPS cost cap and not the HB 2021 cost cap. The draft order noted that if the utility must procure an RPS-eligible resource that is more expensive than an alternative non-emitting resource in order to meet the bundled REC requirements of the RPS, the incremental costs will be attributed to the RPS cost cap and not the HB 2021 cost cap.

2. Positions of the Parties

The Joint Utilities urge us to decline to issue any formal guidance on the question of interaction between the HB 2021 and RPS cost caps, and instead, allow for fact-specific

[77] AWEC Opening Comments at 8-9 (Aug. 12, 2025).

resolution of this issue in future proceedings.[78] The Joint Utilities argue, in addition, that "[a] but-for test[] strikes too firm of a line."[79]

AWEC argues that the HB 2021 cost cap should be applied to investments that are determined to contribute to compliance with HB 2021, regardless of whether those costs are associated with investments that also satisfy the RPS. They claim that it is reasonable to allow costs to count toward both the RPS cost cap and the HB 2021 cost cap because "the RPS and HB 2021 are intended to serve fundamentally different purposes. The Commission has already recognized that HB 2021 is an emissions-based law whereas the RPS is a requirement to acquire renewable resources."[80]

CUB and NWEC/RNW support a but-for test, as described in Section II.A above: costs incurred for RPS compliance would count toward the RPS cost cap but not toward the HB 2021 cost cap. In its comments on the draft order, CUB asks how a project that would be required for the RPS and would be made regardless of HB 2021 could be added to HB 2021 costs, arguing that the counterfactual scenario is meant to propose the least cost/least risk option inclusive of RPS requirements.

3. Resolution

As stated in Section III.C above, a cost or investment is only included in the HB 2021 cost cap if compliance with sections 1 through 15 of HB 2021 is a major driver behind the action. It may frequently be the case, however, that a resource that is acquired for the purpose of HB 2021 compliance will also bring the opportunity to procure the RECs needed to contribute to the utility's compliance with the RPS. We have previously determined that HB 2021 is an emissions based standard[81] and thus many different technologies may provide the least-cost, least-risk path to achieving compliance with HB 2021's annual requirements. Some of those technologies will also support compliance with the RPS by producing RECs that the utility can procure and retire. As AWEC highlights, the RPS centers on RECs for compliance, utilizing inter-annual banking and the use of both bundled and unbundled RECs. The actual or imputed cost of RECs is clearly only applicable to the RPS cost cap and not the HB 2021 cost cap.[82] The

[78] Joint Utilities Opening Brief at 7 (May 23, 2024).
[79] Joint Utilities Response Brief at 5 (June 20, 2024).
[80] AWEC Opening Brief at 11 (May 23, 2024). As noted in Section III.C above, AWEC argues at page 6 of its initial brief that costs incurred to comply with other statutes, including the RPS, can count toward the HB 2021 cost cap because "each of these separate legal mandates share a common purpose with HB 2021; that is, carbon emissions reduction."
[81] Order No. 24-002 at 5, 12-13.
[82] *See* section III.C above, stating that where HB 2021 is a significant purpose, but other drivers exist as well, we will consider the appropriate portion of the cost or investment for inclusion in the cost cap, aiming to estimate a proportional allocation of an investment's costs across drivers.

evaluation becomes yet more fact-specific and complex if the utility must procure an RPS-eligible resource that is more expensive than an alternative non-emitting resource in order to meet the bundled REC requirements of the RPS. If this limitation requires such a procurement, the incremental costs (i.e., the difference between the alternative HB 2021-compliant but RPS-ineligible resource and the RPS-eligible resource) will be attributed to the RPS cap and not the HB 2021 cap.

We reiterate that the results of the utility's counterfactual analysis are not dispositive evidence of whether HB 2021 compliance is a significant purpose of an action. However, if we find that, although an action reduces a utility's greenhouse gas emissions, HB 2021 compliance is *not* a major driver of the action, our inquiry would end there.

F. Time period for cost cap application

Section 10 appears to contemplate that the Commission will forecast and then track the revenue requirement impact of all investments or costs determined to "contribute to compliance," authorizing a pause in utility compliance if their "actual or anticipated cumulative rate impact * * * exceeds six percent of revenue requirement for a year." Is the statute clear that the cost cap applies only in individual years, based on the relevant costs experienced in a single year as a percentage of that same year's revenue requirement (i.e., without considering past or future years)?

1. Draft Order

The draft order proposed to determine that the cost cap applies only in individual years, based on the relevant costs experienced in a single year as a percentage of that same year's revenue requirement. It proposed that we consider evidence submitted to us in a section 10 request regarding the impact of any new or modified costs or investments impacting rates in a year for which we have not granted an exemption, as well as any actual or proposed rate change, in ruling on whether an exemption is warranted for that year. Under that approach once we have granted an exemption for a particular year, that year's exemption would not be subject to later revocation based on new information.

2. Positions of the Parties

Joint Utilities, CUB, and NWEC/RNW agree that the cost cap applies only in individual years. AWEC's interpretation is that "all costs that are determined to contribute to compliance would be forecasted out for the time period that the investment or cost would affect rates."[83] This exercise would include forecasting, for the depreciable life of the resource, the resource's cost, power cost impacts ("likely using forward prices assumed in the utility's IRP"), and tax impacts, as well as forecasting the utility's revenue requirement "for as long as the costs that contribute to HB 2021 compliance are assumed to impact rates."[84]

CUB notes HB 2021's provision for future adjustments to the cumulative rate impact if the initial accounting was based upon the forecasted impact, raising the question of how often, and in what context, the Commission will update forecasted costs with the actual costs incurred. CUB suggests that the utilities be required to provide such updates in their annual CEP updates, in preference to holding separate, time-consuming cost cap review proceedings.

Where an exemption has been granted, AWEC advocates for using general rate cases as the forum in which to evaluate whether the exemption should remain in force, arguing that (1) a general rate case is likely to materially impact the utility's revenue requirement; (2) a general rate case will capture new cost-cap-eligible actions during the forecast period that were not accounted for in the original cost cap proceeding; (3) the depreciation of a resource is only updated in a general rate case; and (4) limiting reviews of cost cap exemptions to general rate cases would be less administratively burdensome than conducting annual reviews of in-force exemptions.

3. Resolution

We agree with commenters that the cost cap applies only in individual years, based on the relevant costs projected to be experienced in a single year as a percentage of that same year's projected revenue requirement. As a practical matter, the costs that make up the annual revenue requirement can change substantially from year to year as power costs absorb fuel cost changes, short term contracts and resource variability such as low hydro forecasts. We leave to further development how cost cap reporting, including updates to a utility's projected revenue requirement for a particular year, should be made prior to a determination that the utility is projected to reach the six percent limit for that year.

If, with respect to a given year, we have previously determined that the cost cap has not yet been met, we will consider evidence submitted to us in a section 10 request regarding the impact of any new or modified costs or investments impacting rates in that year, as well as any actual or proposed rate change, in ruling on whether an exemption is warranted for that year. Once we have granted an exemption for a particular year,

[83] AWEC Opening Brief at 11 (May 23, 2024) (internal citations and quotations omitted).
[84] *Id.* at 12.

however, that year's exemption is not subject to later revocation based on new information. We do not interpret section 10 as contemplating revisiting exemptions granted pursuant to subsection (4), which will, as directed by the statute, be narrowly tailored and limited in duration. Additionally, particularly given the long lead time necessary to come into compliance with the emission reduction targets, an exemption from compliance that could be revoked at any time prior to, or even during, the year at issue would be no exemption at all. And any exemption must be set out as a glide path that paces investment towards ultimate compliance.

We note for the sake of clarity that the cost cap does not permit an additional six percent rate increase every year; instead, for a given year, we are to consider the cumulative impact on that year's rates of all costs or investments that we have determined contribute to compliance with sections 1 through 15 of HB 2021 as compared with the revenue requirement for that year.[85] To the extent they address the issue, the parties seem to share our interpretation of this requirement.[86]

[85] *See* ORS 469A.445(3)(a) ("the commission * * * shall: (a) Cumulatively calculate the rate impact caused by all investments or costs that have been the subject of a proceeding pursuant to this section, and must be included in calculation for the time period that the investment or cost would affect rates"); *id*. § 445(4).
[86] *See*, *e.g.*, Joint Utilities Initial Brief at 9 ("if utilities were to procure several rate-based assets, and the cumulative costs from these resources was projected to exceed the cost cap throughout the depreciable lives of the assets * * *, the Commission would be justified in allowing a continuing cost cap exemption for the depreciable lives of these resources (assuming that an annual cost cap compliance filing demonstrates that the relevant costs continue to exceed six percent of a utility's then-current annual revenue requirement)"; CUB Opening Brief at 20 (May 23, 2024) ("CUB believes the HB 2021 cost cap applies to the new costs associated with that single, specific year. The cumulative nature is that it includes that specific year's rate impact caused by previous year's investments if those investments contributed to compliance").

IT IS ORDERED that: The Administrative Hearings Division is directed to open a rulemaking proceeding as set forth herein.

Made, entered, and effective January 30, 2026.

Letha Tawney
Chair

Les Perkins
Commissioner

Karin Power
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001- 0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.