

**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.

NW ENERGY COALITION AND  
RENEWABLE NORTHWEST REPLY  
COMMENTS

**I. INTRODUCTION**

NW Energy Coalition (“NWEC”) and Renewable Northwest (“RNW”) appreciate the opportunity to submit these Reply Comments to the Oregon Public Utility Commission (“Commission”) regarding the cost cap established by House Bill 2021 (2021) (“HB 2021”), in accordance with Administrative Law Judge (“ALJ”) Mapes’s September 2, 2025 Memorandum (“Memorandum”) and ALJ Allwein’s September 5, 2025 Ruling. We focus these Reply Comments around responses to the questions set forth in the Memorandum. We continue to broadly support the direction the Commission has signaled to stakeholders – including in the draft order and the August 28, 2025 Workshop (“Workshop”) in this docket – and we appreciate the challenges of ensuring the resulting Order provides the groundwork for a functional process that accounts for real-world conditions and costs without the lengthy, resource-intensive process of an Integrated Resource Plan (“IRP”) or rate case proceeding. RNW and NWEC urge the Commission to adopt a principled process that is as simple and streamlined as possible while ensuring accuracy. Overall, we continue to appreciate the Commission’s thoughtful deliberation on issues raised by HB 2021’s cost cap and its attention to these important issues.

## II. COMMENTS

NWEC and RNW frame these comments around the questions set forth in the Memorandum. We reproduce each question as presented in the Memorandum and provide a response.

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

Consistent with the direction in the draft order prepared by the Administrative Hearings Division (“AHD”) in this matter, RNW and NWEC believe ORS 469A.445 calls for the Commission to issue an exemption if actual or projected compliance costs have reached or exceeded 6% of its projected revenue requirement for that year. A plain language review of ORS 469A.445 coupled with the practicalities of needing to rely on actual revenue requirement impacts render this interpretation valid. It is RNW and NWEC’s position that the statute does not intend to prevent a utility’s projected obligatory compliance costs from reaching 6%. That is, the utility should not be relieved of its compliance obligation due to anticipated costs in the IRP or early in the Request for Proposals (“RFP”) process, which the draft order has found are insufficient to support a cost cap determination.<sup>1</sup> RNW and NWEC support the draft order’s finding that “utility commitment to a project [is] sufficient to meet the definition of ‘forecast costs[.]’”<sup>2</sup>

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<sup>1</sup> Notice and Memorandum, UM 2273 Draft Order, Appx. A, p. 10 (May 27, 2025) (hereinafter “Draft Order”).

<sup>2</sup> *Id.* at 11.

In an ideal world, the utilities will continually procure resources to further their binding directive to demonstrate continual progress towards HB 2021’s mandates and proactively plan to avoid hitting the cost cap. To that end, we agree with the draft order that utilities “should monitor the cumulative incremental rate impacts of [their] existing *and planned* cost-cap-eligible costs and investments vis-à-vis its projected annual revenue requirements[.]”<sup>3</sup> Therefore, to the extent practicable, the utilities should contour their RFPs at the outset to fit within the cost cap while making continual progress. In RNW and NWEC’s view, an RFP that is somewhat diminished in scale – yet results in procurement – is superior to an approach that results in a larger RFP that triggers the cost cap and leads to no procurement in the following year, which would potentially lead to the utility falling behind HB 2021’s mandates. The utilities should consider their obligation to demonstrate continual progress proactively in their planning and procurement processes.

RNW and NWEC’s position that ORS 469A.445 calls for the Commission to issue an exemption if actual or projected compliance costs have reached or exceeded – rather than preventing them from reaching – 6% of its projected revenue requirement for that year is corroborated by Oregon statutory interpretation law. Statutory interpretation requires discerning the intent of the legislature.<sup>4</sup> The first step in doing so is examining “both the text and context of the statute.”<sup>5</sup> If the legislature's intent is not clear from the text and context inquiry, the next step is considering legislative history.<sup>6</sup> If legislative intent is still unclear, the next step is to apply

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<sup>3</sup> *Id.* emphasis in original.

<sup>4</sup> *Portland Gen. Elec. Co. v. Bureau of Labor & Indus.*, 317 Or 606, 610 (1993) citing ORS § 174.020.

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

<sup>6</sup> *Id.* at 611.

maxims of statutory construction.<sup>7</sup> In *State of Oregon v. Gaines*, the Oregon Supreme Court stated:

there is no more persuasive evidence of the intent of the legislature than “the words by which the legislature undertook to give expression to its wishes.” *State ex rel Cox v. Wilson*, 277 Or 747, 750, 562 P2d 172 (1977) (quoting *U.S. v. American Trucking Ass'ns.*, 310 US 534, 542-44, 60 S Ct 1059, 84 L Ed 1345 (1940)). Only the text of a statute receives the consideration and approval of a majority of the members of the legislature, as required to have the effect of law. Or Const, Art IV, § 25. The formal requirements of lawmaking produce the best source from which to discern the legislature’s intent, for it is not the intent of the individual legislators that governs, but the intent of the legislature as formally enacted into law.<sup>8</sup>

Under Oregon law, the text and context of the statute in question are given the primary weight in the three step *State v. Gaines* statutory interpretation process.<sup>9</sup> When examining a statute’s text and context, the Commission gives words of common usage “their plain, natural, and ordinary meaning.”<sup>10</sup>

ORS 469A.445(4) provides, in pertinent part, that the Commission must provide an exemption from HB 2021 compliance “[u]pon a determination that the *actual* or *anticipated* cumulative rate impact . . . exceeds six percent of the annual revenue requirement for a year[.]”<sup>11</sup>

Relevant to this inquiry is whether the Oregon Legislature’s use of “actual or anticipated cumulative rate impact” indicates an intent for the utility to be relieved of its compliance obligation based upon projected costs, rather than those that can be determined with a high degree of certainty. RNW and NWEC support the draft order’s finding that section 10 filings

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<sup>7</sup> *Id.* at 612.

<sup>8</sup> *State v. Gaines*, 346 Or 160, 171, 206 P3d 1042 (Apr. 30, 2009).

<sup>9</sup> *In re Portland General Electric Company, Application for Transportation Electrification Programs*, OPUC Docket No.UM 1811, Order No. 18-054 at 7-8 (Feb. 16, 2018); *in re PacifiCorp, dba Pacific Power, Petition for Declaratory Ruling Regarding ORS 757.480*, OPUC Docket No. DR 47, Order No. 14-254 at 4 (Jul. 8, 2014).

<sup>10</sup> Docket No. DR 47, Order No. 14-254 at 4 (citing *Portland Gen. Elec. Co. v. Bureau of Labor & Indus.*, 317 Or 606, 859 (1993)).

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

must rely on the impact of costs already in utility rates or, at their most attenuated, when a utility has committed to a project at the end of an RFP.<sup>12</sup>

A plain language reading of the pertinent statutory language confirms this position, as the intent is clear on its face. Webster’s Dictionary defines “actual” as “existing in fact or reality”<sup>13</sup> while “anticipated” is defined as “expected or looked forward to.”<sup>14</sup> Taken a step further, “expected” is defined as “to consider probable or certain.”<sup>15</sup> Anticipated costs, then, are those that can be considered as probable or certain to enter into utility rates to then be assessed against the cost cap. The draft order’s finding that costs in a utility’s decision to commit to a project at the end of the RFP are sufficient to meet the definition of “forecast cost” is therefore reasonable. There are many shifting facts mid-stream in an RFP that would affect the scope of costs that would eventually enter into utility rates. For example, different resources on an RFP’s final shortlist are subject to different ownership structures. Depending on the ownership structure, resources may be eligible for the utility to earn a rate of return and may be recovered through a general rate case or Renewable Resources Automatic Adjustment Clause filing, or recovered through power costs as a power purchase agreement.

Potentially relieving a utility of its HB 2021 compliance obligation should not be taken lightly. The Oregon Legislature created binding mandates by which the utilities must decarbonize their systems while being mindful of the impact to utility customers. While the cost cap is an important and negotiated customer protection measure embedded in the law, the

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<sup>12</sup> Draft Order at 10-11.

<sup>13</sup> *Definition of ACTUAL*, Merriam-Webster (accessed Sept. 29, 2025), <https://www.merriam-webster.com/dictionary/actual>.

<sup>14</sup> *Definition of ANTICIPATED*, Merriam-Webster (accessed Sept. 29, 2025), <https://www.merriam-webster.com/dictionary/anticipated>.

<sup>15</sup> *Definition of EXPECT*, Merriam-Webster (accessed Sept. 29, 2025), <https://www.merriam-webster.com/dictionary/expect>.

Commission must utilize the best possible information with which to assess whether it should take the significant step of pausing compliance. As the draft order notes, the utilities have the best access to information with which to assess the cost cap and, in RNW and NWECA's view, should carefully plan and procure as many new resources as necessary to meet the law's mandates while working to ensure the cap is not triggered.

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

As we discuss briefly below, RNW and NWECA recommend that a section 10 filing should be based in significant part on the (1) embedded revenue requirement from a utility's last general rate case, (2) adjusted for power costs plus (3) the impact of any single-issue ratemaking mechanisms that the Commission has granted cost recovery for, and (4) evidence of the rate impact of a resource investment or investments developed according to the methodology typically used in those single-issue ratemaking mechanisms, such as the renewable resource automatic adjustment clause. This approach uses data and analytical methods from other well-defined contexts rather than seeking to establish novel requirements for the cost cap. Moreover, the approach would not require a section 10 proceeding to become, effectively, a full rate case. Additionally, RNW and NWECA believe that a party bringing forth a section 10 claim should ultimately bear both the burden of proof and burden of persuasion to justify their position that the cost cap has been hit.

Beyond the evidence discussed above, additional evidence will be necessary to determine whether and to what extent HB 2021 was a major driver of a utility investment. HB 2021-compliant resources may be selected for economic reasons, or to meet Renewable Portfolio

Standard (“RPS”) obligations, or to meet customer demand for clean resources. To assess whether an HB 2021-compliant resource was selected for economic reasons, a counterfactual portfolio will be a helpful but not dispositive tool, as discussed in past comments and the August 28 Workshop. Evidence regarding the appropriateness of a utility’s analytical methods for determining the counterfactual portfolio may be relevant to the question of how much weight a counterfactual portfolio should receive, if any. For example, if the counterfactual portfolio is based on an analysis that uses implausibly low prices for thermal resources, fails to account adequately for fuel price volatility, ascribes too high a capacity contribution to resources subject to high failure rates during high-need hours, or assumes a novel resource may be available on an unrealistic timeframe, that portfolio should likely receive little weight.

The discussion above also mentioned RPS needs and resources used to serve customers of voluntary renewable programs. On the former point, a utility’s RPS Compliance Report may provide helpful information. On the latter point, the planned rate treatment of a resource investment will also be relevant – for example, if customers enrolled in a voluntary renewable program are directly bearing any above-market costs of an HB-2021 compliant resource, that information will be important to ensure that those costs are not wrongly included in determining the application of the cap.

There may be additional evidence that bears on whether factors beyond HB 2021 led to the selection of a resource. For example, RNW and NWEC are concerned that PacifiCorp may seek to attribute costs of HB 2021-compliant resources to Oregon customers exclusively even if the resource provides benefits to customers in other PacifiCorp states. This allocation issue is currently actively being investigated in PacifiCorp’s ongoing IRP. Just as the Commission should seek to ensure that Oregon customers are only paying for costs attributable to their utility

service, so the Commission should also ensure that the cost cap is not triggered by investments used to serve customers outside Oregon. Thus, evidence bearing on the appropriate cost allocation of a resource will also be appropriate for a section 10 proceeding.

RNW and NWECC recommend that the Commission treat the list above as indicative, not as a closed set of factors on which evidence could be appropriate depending on case-specific circumstances. Any Commission order on the cost cap should allow room for the presentation of additional evidence that could bear on whether HB 2021 was a major driver of a utility investment, should any factors not currently contemplated emerge.

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

As discussed in the draft order, the Commission should address power costs by considering their impact to both the numerator and denominator within an individual year if a section 10 filing is made.<sup>16</sup> Power costs fluctuate annually and are set in proceedings that forecast their costs – PacifiCorp’s Transition Adjustment Mechanism (TAM) and Portland General Electric’s Annual Update Tariff (AUT). After a contested case, the forecasted power costs set in the TAM and AUT enter into customers’ rates on January 1 of each year. Therefore, the Commission and parties with section 10 filing rights will know the impact that power costs will have on a utility’s overall revenue requirement on an annualized basis. When considering whether the 6% cost cap has been hit, a Section 10 proceeding should consider the impact that fluctuating power costs have on the utility’s revenue requirement – inclusive of any true-ups that

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<sup>16</sup> Draft Order at Appx. A, p. 14 (“We agree with commenters 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. 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.”).

may occur in a Power Cost Adjustment Mechanism proceeding that alters the power costs recovered in customer rates upwards or downwards.

In addition to considering the impacts of power costs in the denominator of a section 10 proceeding, the Commission must also consider their impact to the numerator. Power costs include the impacts of purchase power expenses that may count towards HB 2021 compliance. Therefore, a Section 10 proceeding should account for resources recovered through power costs of which HB 2021 compliance was a major driver. The Commission should apply the same analysis to consider the impact of these resources that it would for other resources. As articulated in the draft order, resources should be considered in the cost cap analysis if HB 2021 was a major driver behind the cost or investment.<sup>17</sup> In conducting this analysis, the Commission should examine whether other drivers exist as well and assign the “appropriate portion of the cost [ ] for inclusion in the cost cap.”<sup>18</sup>

In addition to utilizing the revenue requirement set in a utility’s prior general rate case and power costs that fluctuate on an annual basis, the Commission should also consider the impact of single-issue ratemaking mechanisms as they enter rates. For example, PacifiCorp and PGE are authorized to recover the costs of wildfire mitigation plans and associated investments through an automatic adjustment clause. These costs are recovered annually from customers and, like power costs, fluctuate on a yearly basis. A section 10 filing should consider the impact of these costs – as well as other automatic adjustment clauses and deferred accounting applications – in the denominator. Just as any other cost or investment used in a section 10

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<sup>17</sup> Draft Order at Appx. A, p. 6.

<sup>18</sup> *Id.*

proceeding, actual costs should be used for the denominator to the extent it is practicable to do so, and anticipated costs should be used if they can be assessed with a high degree of certainty.

One specific automatic adjustment clause utilized by both PacifiCorp and PGE warrants closer examination in this proceeding and in future section 10 proceedings. The Renewable Resources Automatic Adjustment Clause (“RAC”) was established by SB 838 to recover costs associated with RPS-eligible resources. While the RPS cost cap should be viewed and assessed separately from the HB 2021 cost cap, as the draft order notes, there may be instances where a resource is used for both HB 2021 and RPS compliance purposes.<sup>19</sup> While outstanding legal questions remain regarding whether the RAC can be utilized to recover the costs of HB 2021 resources, it is appropriate to address its hypothetical applicability in the context of this proceeding. If an HB 2021-compliant resource is recovered through the RAC, it should be determined which portion of the resource was acquired for HB 2021 and separate those costs out from those that were incurred to meet the RPS. Unlike capital investments that are recovered through a general rate case process, the RAC updates depreciation expense on an annual basis. Therefore, when considering the impact of costs recovered through the RAC to the HB 2021 cost cap, a section 10 filing must ensure that costs are updated annually to account for depreciation.

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<sup>19</sup> Draft Order at Appx. A, p. 13.

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

The discussion above reflects simplifying assumptions that should help to meet RNW and NWECS – and, we think, the Commission’s – goal of ensuring that a section 10 analysis reflects real-world circumstances and costs without ballooning into a full combination IRP and rate case.

For example, after reflecting on the discussion at the August 28 Workshop and the Commission’s questions set forth in the Memorandum, RNW and NWECS recommend that the denominator in a section 10 filing should be the embedded revenue requirement adjusted for power costs plus the impact of any single-issue ratemaking mechanisms that the Commission has granted cost recovery for, or will grant cost recovery for in the course of a section 10 proceeding. This approach uses data from other well-defined contexts rather than seeking to establish a new revenue requirement as in a utility general rate case. As such, it is effectively simplified.

Similarly, RNW and NWECS recommend that the numerator in a section 10 filing should be determined in a similar manner to a utility’s calculation of the rate impact of a resource for which the utility is seeking cost recovery under the RAC. Again, this approach does not require effectively running a new integrated resource plan or full general rate case. Rather, it builds on existing processes and values to determine the rate impacts of a resource.

The challenging part will be determining whether some or all of a resource should be included in both the numerator and denominator. Because HB 2021-compliant resources may be selected for economic reasons, or to meet RPS obligations, or to meet customer demand for clean resources, the denominator will have to be further adjusted to include resource costs for which

HB 2021 was not a major driver. RNW and NWEC expect that this part of the section 10 analysis is where parties are likely to have the most disagreement.

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

The IRP/CEP stage is not an appropriate point in the planning and procurement process for a section 10 filing, but it may provide a useful signal indicating that a utility might be approaching the cost cap in order to achieve compliance with HB 2021’s emission-reduction requirements. Indeed, the draft order considers how these processes may interplay with the cost cap and signals that the utilities “should monitor the cumulative incremental rate impacts of [their] existing *and planned* cost-cap-eligible costs and investments vis-à-vis its projected annual revenue requirements[.]”<sup>20</sup> IRPs and CEPs use proxy resources with indicative, not actual, cost inputs to determine a procurement plan. The actual resources that a utility procures typically bear only a limited relationship with the resources identified in the preferred portfolio of a utility’s IRP, as RNW and NWEC discussed in their Opening Comments.<sup>21</sup>

Additionally, IRPs and CEPs may use problematic cost inputs that send a misleading signal. For example, the proxy resource costs PacifiCorp used in its 2023 IRP were “far above the consensus” and “overstated the effects of inflation” with the result that “if PacifiCorp had incorporated supply-side costs for renewables that were more in line with PGE, CPUC, and NREL ATB, it is likely that PLEXOS LT would select more of these resources instead of higher-cost alternatives, such as nuclear, non-emitting peakers, and fossil units.”<sup>22</sup> In other words,

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<sup>20</sup> Draft Order at Appx. A, p. 11 (emphasis in original).

<sup>21</sup> Docket No. UM 2273, NW Energy Coalition and Renewable Northwest Opening Comments at 4-5 (Aug. 12, 2025).

<sup>22</sup> Docket No. LC 82, Order No. 24-073, Appendix A at 51-52 (Mar. 19, 2024).

incorrect inputs can suggest that HB 2021-compliant resources will be cost drivers when real-world inputs suggest those same resources will save customers money. Thus, even the indicative value of an IRP or CEP regarding the likelihood that a utility may trigger the cost cap is limited.

With an RFP, resource costs move from proxy costs to the bid costs of real resources. However, even the final shortlist stage of an RFP may be misleading as to what resources a utility will actually procure, again as discussed in RNW and NWECA's Opening Comments. However, once a utility begins executing contracts for a resource, the costs of that resource are known ("actual") and reasonably likely – but not certain – to be moved into customer rates ("anticipated"). Once a contract is executed, there may be enough information for a utility or an entity with section 10 filing rights to initiate a section 10 proceeding. There will not yet be enough information for any entity to state conclusively that the cost cap is triggered, because it will not yet be known whether HB 2021 was a major driver of the resource acquisition.

Just because the best timing for a section 10 filing is after at least one contract is signed, that does not indicate that the RFP shortlist stage is irrelevant to the section 10 calculus. As discussed above, ideally a utility will structure its RFP to come under or butt against the cap without exceeding it. But again, doing so will be an art, not a science. After all, it will be for the Commission to determine whether any putative rate increase is driven by costs for which HB 2021 was a major driver, as opposed to costs undertaken for economic or other reasons. If a section 10 filing is made before even one contract is signed, given the myriad other disruptions taking place in the industry today, it may well be that the procurement decisions necessary to meet HB 2021 are postponed indefinitely and the policy of the law is never fulfilled.

### III. CONCLUSION

In the September 21, 2025 edition of the New York Times Magazine, David Wallace-Wells described how, since HB 2021 was passed four years ago, “climate politics is in undeniable withdrawal[.]”<sup>23</sup> “What changed?” he asks – “In short, everything but the science, which [has] continued to generate grim warnings about the speed and consequences of temperature rise[.]” Even as the world gets more complicated and its problems arguably more difficult to solve, RNW and NWECA offer this context to encourage the Commission to continue its work to meet this challenging moment and ensure that implementation of the cost cap is consistent with the policy of HB 2021 “[t]hat retail electricity providers rely on nonemitting electricity ... and eliminate greenhouse gas emissions associated with serving Oregon retail electricity consumers by 2040.”<sup>24</sup>

NW Energy Coalition and RNW appreciate the Commission’s consideration of these Reply Comments. We thank the Commission for its continued thoughtful attention to implementing the cost cap in a manner consistent with the language and policy of HB 2021.

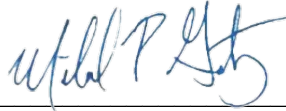
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<sup>23</sup> David Wallace-Wells, It Isn’t Just the U.S. The Whole World Has Soured on Climate Politics. New York Times Magazine (Sept. 21, 2025).

<sup>24</sup> ORS 469A.405(1).

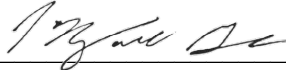
Dated this 29th day of September 2025.

Respectfully submitted,



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