ORDER NO. 24-002

ENTERED Jan 5, 2024

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

This order resolves several questions we posed in a June 5, 2023, scoping order[1] regarding our implementation of HB 2021.[2] We discuss and resolve each question in turn and direct the Commission's Administrative Hearings Division to initiate Phase II of these proceedings to address HB 2021's cost cap provisions.

In this order, we conclude that: (1) the text and context of the statute point unambiguously to the conclusion that compliance with HB 2021's emissions reductions requirements need not be demonstrated through REC retirement; (2) we decline at this time to articulate any specific additional factors we will explicitly consider in determining whether a CEP is in the public interest under HB 2021 section 5(2)(f); (3) HB 2021 does not assert a requirement or preference for in-state resources, but we intend to seek information about direct benefits to communities in Oregon; and (4) our existing CEP and IRP review processes are appropriate for making regular determinations that utilities are achieving continual progress at an appropriate pace of action and that determinations on continual progress will be final orders subject to judicial review.

I. LEGAL BACKGROUND

In 2021, the Oregon Legislature passed, and the Governor signed, HB 2021 into law. Among other things, HB 2021 set emissions reductions targets for certain of the state's retail electricity providers, including electric companies[3] and electricity service suppliers, and established requirements to ensure progress toward and compliance with the targets. Specifically, HB 2021 established the following emissions reduction targets:

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[1] Order No. 23-194 (June 5, 2023).
[2] HB 2021 was codified in ORS 469.400 *et seq*., as well as in amendments to ORS 469A.005, 469A.205, 469A.210, 757.247, 757.603, 757.646, and 757.649.
[3] ORS 469A.480 exempts Idaho Power Company from HB 2021, making PacifiCorp and Portland General Electric the electric companies subject to the law.

a. By 2030, 80 percent below baseline emissions level;
b. By 2035, 90 percent below baseline emissions level; and
c. By 2040, and for every subsequent year, 100 percent below baseline emissions level.[4]

Implementation of various elements of HB 2021 is assigned to the Oregon Department of Environmental Quality (DEQ), the Oregon Department of Energy (ODOE), and the Public Utility Commission of Oregon (PUC). DEQ and the PUC share responsibilities related to evaluating compliance with HB 2021's emissions targets, with DEQ establishing each utility's emissions baseline and providing emissions information to the PUC for our ultimate determination of compliance, including application of any reliability or cost-related adjustments to compliance requirements.[5]

The PUC also has responsibility for evaluation of clean energy plans (CEPs). For electric companies subject to HB 2021, the law requires CEPs to be developed concurrent with the development of integrated resource plans (IRPs),[6] which we have required and overseen as part of the ratemaking process for more than three decades.[7] CEPs, among other things, must incorporate HB 2021's clean energy targets, demonstrate continual progress towards meeting them, and result in "an affordable, reliable and clean electric system"[8] We are tasked with "ensur[ing] that an electric company demonstrates continual progress * * * and is taking actions as soon as practicable that facilitate rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers."[9] We are directed to acknowledge CEPs if they are consistent with the emission reduction targets and the public interest, considering a non-exclusive list of public interest factors.[10]

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[4] ORS 469A.410(1).
[5] *See* ORS 469A.420(1) (DEQ's role in determining emissions reductions baseline and targets); ORS 469A.420(4)(a) (reporting requirement to DEQ); ORS 469A.420(4)(b) (PUC's role in determining compliance); ORS 469A.435 (determining compliance with clean energy targets); ORS 469A.440 (process for temporary exemption of compliance for reliability or cost reasons).
[6] OAR 469A.415(1).
[7] *See In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 (Apr. 20, 1989) (adopting "least-cost planning" as the preferred approach to utility planning); *In the Matter of Public Utility Commission of Oregon, Investigation Into Integrated Resource Planning,* Docket No. UM 1056, Order No. 07-002 (Jan. 8, 2007) (adopting integrated resource planning as the preferred approach to resource planning) and Order No. 07-047 (Feb. 9, 2007) (publishing the Commission's complete IRP guidelines); Order No. 08-339 (adopting a revised Guideline 8).
[8] ORS 469A.415(4).
[9] ORS 469A.415(6).
[10] ORS 469A.420(2).

II. PROCEDURAL BACKGROUND

On February 21, 2023, Commission Staff requested we initiate this docket to investigate issues related to HB 2021 implementation. On March 16, 2023, Chief Administrative Law Judge Nolan Moser issued a memorandum (revised by ruling dated March 22, 2023) establishing a scoping process and identifying scoping questions to help the Commission resolve HB 2021 implementation issues. The scoping process included two opportunities in April 2023 for submitting written comments, as well as an April 18, 2023, scoping workshop for Commissioner discussion and dialogue with interested stakeholders. We received scoping comments from the Oregon Citizens' Utility Board (CUB), Portland General Electric Company (PGE), PacifiCorp, New Sun Energy LLC, Center for Resource Solutions, 3Degrees Group Inc., Green Energy Institute, Sierra Club, Rogue Climate, Metro Climate Action Team, Oregon Solar + Storage Industries Association (OSSIA), Climate Solutions, Renewable Northwest, Coalition of Communities of Color, and NW Energy Coalition.

After reviewing the extensive comments submitted during the scoping process, we issued a scoping order on June 5, 2023. Our scoping order articulated the issues to be addressed as well as their sequencing and the process to resolve those issues in a phased process.

Our scoping order posed four questions we anticipated answering as part of Phase I(a) of the Commission's HB 2021 implementation process:

- I(a)(1): Can and should the Commission require retirement of Renewable Energy Certificates (RECs) to demonstrate compliance with HB 2021? Does the answer depend on how the Oregon Department of Environmental Quality (DEQ) interprets and implements ORS 468A.280? If the Commission does not require retirement of RECs, can and should it otherwise restrict their use by utilities subject to HB 2021?
- I(a)(2): Before applying the "public interest" criterion for CEP acknowledgment, should the Commission give guidance on its interpretation of "economic and technical feasibility" or other specified factors in HB 2021 section 5(2)? Should the Commission pre-determine other relevant factors for purposes of section 5(2)(f)?
- I(a)(3): What relevance can and should the statements of policy in HB 2021 section 2 have to the Commission's implementation of the operative provisions of the law?
- I(a)(4): What procedural approach should the Commission take to oversee continual progress and prompt action by utilities, as required by HB 2021 section 4(6)?

The scoping order also provided our preliminary expected resolution for each of those four questions and asked parties and the public to provide briefing and comments on those preliminary determinations.

We also identified three Phase I(b) issues and questions that would help us determine whether and how to initiate a second phase of our HB 2021 implementation:

- I(b)(1): Are there threshold issues of interpretation related to HB 2021, section 10 ("Cost Cap for electric utilities") on which advance Commission guidance would be useful and beneficial?
- I(b)(2): Are there programs and issues areas the Commission should revisit related to Oregon-regulated REC programs that could be impacted by our decision regarding REC retirement in Phase I(a)?
- I(b)(3): How and when should the Commission consider early compliance incentives, including how the Commission could consider early compliance incentives narrowly enough to be feasible in the near-term?

As part of Phase I(b), we also asked parties and the public to identify other threshold issues for resolution in Phase II where Commission guidance would make upcoming Staff-led HB 2021 implementation proceedings more efficient.

We asked parties to submit briefing and for the public to submit comments on the Phase I(a) and Phase I(b) questions. Before opening briefs and comments were due, we held a public workshop on RECs on June 29, 2023. We received briefing from Climate Solutions, Columbia Riverkeeper, CUB, PGE, PacifiCorp, NW Energy Coalition, Renewable Northwest, NewSun Energy, Green Energy Institute, Sierra Club, Rogue Climate, Coalition of Communities of Color, Oregon Storage + Solar Storage Industries Association, Columbia River Inter-Tribal Fish Commission (CRITFC), Pine Gate Renewables, LLC, Community Renewable Energy Association, and Western Power Trading Forum.[11] We received comments from Center for Resource Solutions, Metro Climate Action Team, 3 Degrees Group, Multnomah County Office of Sustainability, City of Portland Bureau of Planning & Sustainability, Verde, Oregon Just Transition Alliance, Oregon Department of Energy, and the U.S. Environmental Protection Agency.[12]

We held an oral argument on November 17, 2023. After the oral argument, the Administrative Law Judge allowed parties and the public to submit final written comments. Final comments were received on November 29, 2023, from Center for Resource Solutions, Pine Gate Renewables, New Sun Energy, and Green Energy Institute.

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[11] We received extensive briefing and comments from numerous parties and organizations in this docket. Because of the extent of and frequently overlapping nature of the arguments, this order does not explicitly summarize the specific arguments of each individual brief and comment received. We did, however, review and consider all the thoughtful filings and arguments we received in reaching our decisions here.

[12] We afford comments from non-parties with the appropriate weight in reaching our decision.

III. DISCUSSION AND RESOLUTION

A. Issue I(a)(1): HB 2021 and Renewable Energy Certificate (REC) retirement

1. Introduction

In the scoping memo, we stated our preliminary conclusion that RECs do not need to be retired to demonstrate compliance with HB 2021. Here, we affirm that conclusion, relying as we must on the text and context of the statute to determine legislative intent.[13] We find the text oriented firmly toward "the emission attributes of the underlying generating resource," and the context of the statute rooted in emissions reductions under DEQ's emissions tracking framework, in sharp contrast to the REC-based compliance framework of Oregon's renewable energy procurement laws. We understand that advocates are concerned about the environmental integrity of HB 2021 in relation to other climate and clean energy policies, and though these concerns do not persuade us to alter our interpretation of HB 2021, we make several observations about how we intend to address such public interest considerations going forward.

2. Background and context

Since approximately 2007, Oregon electric utilities have been subject to state laws relating broadly to the sources and environmental content of electricity. The renewable portfolio standard, the DEQ emissions reporting requirements, and HB 2021 are of primary relevance to the questions we address. Some broader electricity regulation and market context is also important to understanding the issues presented.

a. RPS

In 2007, the Oregon Legislature passed the Oregon Renewable Portfolio Standard (RPS), which required utilities to serve 25 percent of their load from defined renewable energy sources by 2025.[14] In March 2016, SB 1547 increased the RPS requirement to 50 percent by 2040.[15] The law established a compliance system based on renewable energy certificates (RECs). Under Oregon law, a REC represents the environmental, economic, and social benefits, or attributes, associated with the generation of electricity from renewable energy sources, including wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, types of biomass and

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[13] *State v. Gaines*, 206 P.3d. 1042, 1050 (Or. 2009).
[14] *See State of Oregon*, Energy in Oregon-Renewable Portfolio Standard, (accessed on Jan. 3, 2024). https://www.oregon.gov/energy/energy-oregon/Pages/Renewable-Portfolio-Standard.aspx
[15] ORS 469A.052(1)(h).

biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia, as well as some hydropower.[16] One REC is created by the generation of one megawatt hour of renewable electricity. A bundled REC is a REC acquired together with its associated energy such that its recipient receives both the REC and the electricity.[17] An unbundled REC is a REC acquired without its associated energy such that a recipient receives only the REC and not the underlying electricity.[18]

Electric utilities or electricity service suppliers can acquire RECs by generating renewable energy themselves or trading or purchasing RECs. To comply with Oregon's RPS, an entity must retire RECs equivalent to the required percentage of its load, including a specified number of bundled RECs, or make an alternative compliance payment. By retiring a REC, the entity makes a final claim on its environmental attributes and the REC may no longer be transferred or used.[19]

b. DEQ emissions reporting

DEQ has its own physical emissions reporting system, known as the "Oregon Greenhouse Gas Reporting Program," which was created pursuant to ORS 468A.280 and is governed by rules first adopted in 2008 and found in OAR 340, Division 215. Under this system, electric utilities—among others—are required to report actual emissions to DEQ.[20] Electricity suppliers are required to report "emissions related to the generation of electricity delivered or distributed to end users in this state during the previous year, regardless of whether the electricity was generated in this state or imported."[21] DEQ's rules direct electricity suppliers to report emissions from specified generating facilities and unspecified market purchases, with proportional adjustments for multi-jurisdictional utilities and market sales, among other factors.[22]

DEQ's published emissions factors for specified and unspecified electricity sources do not consider the presence or absence of RECs associated with any electricity generated by renewable resources.[23] The "Oregon Greenhouse Gas Reporting Program" emerged after enactment of the RPS in 2007 and has co-existed alongside the RPS since. ORS 468A.280(4)(a)(D)(iii) allows the Environmental Quality Commission (EQC) the discretion to determine a default greenhouse gas emissions factor explicitly for "(e)lectricity purchases for which a renewable energy certificate under ORS 469A.130 (Renewable energy certificates system) has been issued but subsequently

[16] ORS 469A.025.
[17] ORS 469A.005(4).
[18] ORS 469A.005(14)
[19] A more detailed description of Oregon's RPS policy can be found at pages 2-3 of the July 24, 2023, informational comments filed in this docket by the Oregon Department of Energy.
[20] OAR 340-215-0030(2)(C).
[21] OAR 340-215-0120.
[22] OAR 340-215-0120(1).
[23] OAR 340-215-0120(2).

transferred or sold to a person other than the electric company." The EQC has declined to exercise its authority to do so and has not adopted rules determining that default greenhouse gas emissions factor.[24]

c. HB 2021

In 2021, Oregon enacted HB 2021, mandating, among other things, that certain electricity providers reduce greenhouse gas emissions as specified above. Under HB 2021, DEQ determines each electric company's baseline emissions level as well as the quantity of reductions necessary to comply with HB 2021's emissions reduction requirements. HB 2021 explicitly relies upon the continued use of the "Oregon Greenhouse Gas Reporting Program" created through ORS 468A.280 and directs no changes to its implementation.[25] The PUC must use information from DEQ, gathered through this program, to determine compliance with emissions reduction requirements, which begin in 2030.[26]

d. Other relevant industry background and context

RECs are a nationally recognized and traded instrument with a role in both voluntary renewable energy purchasing and in demonstrating compliance with state policies, like Oregon's RPS. RECs are used to track the environmental attributes of electricity produced from renewable resources and are often disaggregated and traded separately from the electricity produced, sometimes called unbundling. Only the holder of the REC has the right to claim the renewable attributes of the resource. The Federal Trade Commission's "Green Guides," codified at 16 CFR 260, provide guidance on environmental attribute claims. They state that if a renewable energy producer "generates renewable electricity but sells renewable energy certificates for all of that electricity, it would be deceptive for the [producer] to represent, directly or by implication, that it uses renewable energy." [27] Claiming use of renewable energy without holding the RECs is considered "double counting"—*i.e.*, when more than one party makes claims to the attributes associated with a REC. Avoiding double claims helps to preserve the integrity of voluntary renewable energy purchases and renewable energy policies.

Although the industry maintains a relatively straightforward and consistent understanding of how RECs carry the right to claim renewable energy attributes, systems for reporting and regulating the direct and avoided greenhouse gas emissions of an electricity generating resource are more varied. As is common elsewhere, RECs in Oregon are defined as including the environmental

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[24] *See generally* OAR 340-215.
[25] ORS 469A.420(1)(a); *Department of Environmental Quality : Oregon Clean Energy Targets : Action on Climate Change : State of Oregon* available at https://www.oregon.gov/deq/ghgp/pages/clean-energy-targets.aspx for baseline emissions level determinations and reduction targets (accessed on Jan. 3, 2024).
[26] ORS 469A.435.
[27] 16 CFR 260.15(d).

attributes associated with electricity generation, although the definition does not directly address direct or avoided GHG emissions attributes and when they are considered to be claimed.[28] Whether and when an entity producing electricity from a non-emitting renewable resource and not retaining the RECs can report zero GHG emissions, and what impact this reporting has on the entity holding the REC, has been a complex question in Oregon and across jurisdictions.[29]

Relevant to this question is the distinction between load-based (also called consumption-based) and generation-based (also called source-based or production-based) emissions accounting and regulatory programs. Generation-based accounting tracks emissions from electricity generation sources, measuring GHG emissions prior to entering the electric grids at the point where electricity is generated.[30] Load-based, or consumption-based, accounting tracks emissions after entering the electric grids at the point where electricity is delivered, sold, or consumed.[31] Generation-based accounting often relies on data reported by electric generating units to the U.S. Environmental Protection Agency (EPA),[32] which is then compiled into the Emissions & Generation Resource Integrated Database (eGRID), a comprehensive inventory of environmental attributes of electric power systems.[33] In contrast, load-based accounting seeks to measure emissions at end use; this is difficult because once electricity enters the grid, it becomes indistinguishable from other sources.[34] As such, load-based accounting must rely on proxy methods, such as RECs, to approximate emissions associated with use of electricity.[35] Generation-based accounting does not rely on RECs because it measures emissions at the point of generation, without seeking to track that electricity to end use or make a claim to its use.[36]

3. Positions of Parties and Commenters

Numerous participants filed briefs and comments in this docket. Some argue that HB 2021 must be interpreted to require the retirement of RECs to demonstrate compliance with the law's

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[28] OAR 330-160-0015(17).

[29] See, *e.g.*, The Brattle Group (June 2023). *Greenhouse Gas and Clean Energy Accounting Methodology Catalog.* available at: https://www.brattle.com/wp-content/uploads/2023/07/2023-06-27-GHG-Accounting-Catalog_v2.pdf (Accessed on Jan. 3, 2024).

[30] Deborah Kapiloff *et al*., *Greenhouse Gas Accounting Systems in Wholesale Regional Electricity Markets: Considerations for the Western Interconnection*, W. RES. ADVOC. (Jan. 2022), available at https://westernresourceadvocates.org/wp-content/uploads/2022/01/2022_0119_GHG_Accounting_-Regional-Markets_f.pdf.

[31] Kapiloff *et al*., *supra* n. 10.

[32] *Id.*

[33] *See* U.S. Environmental Protection Agency Frequently Asked Questions about eGRID website, available at: Emissions & Generation Resource Integrated Database (eGRID)," EPA (2021) (accessed Jan. 3, 2024), available at https://www.epa.gov/egrid/egrid-questions-and-answers

[34] Kapiloff *et al*., *supra* n. 10.

[35] *Id.*

[36] *Id.*

emissions reduction mandate. Others argue that HB 2021 does not require utilities and other regulated suppliers to retire RECs to demonstrate compliance, and that we lack the authority to require otherwise. Because many of the briefs made similar arguments, we do not summarize all the briefs here, but instead mention key arguments made by stakeholders. However, we reviewed and appreciated all the briefs filed and considered them in our decision making.

The most comprehensive statutory argument in support of a requirement to retire RECs was made by the Green Energy Institute at Lewis & Clark (GEI).[37] GEI first argues that HB 2021 is a "load-based program," such that tracking and retirement of RECs must be required as a proxy for delivered electricity; second, it argues that the statute's references to "clean energy" and "clean energy plans" imply delivery to end users and necessitate the retirement of RECs. To support its argument that HB 2021 is load-based, GEI points to several statutory references to end-use customers, such as the provision that requires DEQ to calculate baseline emissions based on "the average annual emissions of greenhouse gas for the years 2010, 2011, and 2012 associated with the *electricity sold to retail electricity consumers.*"[38] GEI then points out that in HB 2021 the Legislature expressly set "clean energy targets" with knowledge that "clean" attributes of electricity are carried with RECs; "[f]rom a legal standpoint, renewable energy is only 'clean' if the electricity is matched with a REC," GEI asserts. GEI, in its final comments, urges the Commission to make clear that HB 2021 is "generation-based" if it concludes that REC retirement is not required.

Sierra Club, Rogue Climate, Columbia Riverkeeper, and Coalition of Communities of Color support GEI's arguments. Other parties also argue for a requirement that RECs be retired, including the Oregon Solar + Storage Industries Association, Center for Resource Solutions (CRS), the Metro Action Climate Team, NewSun Energy, LLC, Pine Gate Renewables, LLC, and the Columbia River Inter-Tribal Fish Commission. CRS argues that HB 2021 is best understood as a load-based policy, because HB 2021 regulates load-serving entities and the emissions associated with serving their customers; interpreting HB 2021 "as a [generation]-based program for LSEs covering emissions from the sources from which the utility procures electricity [] would be confusing to customers and other states and programs," CRS asserts. If the Commission nonetheless takes this direction, CRS encourages clarification and disclosure that "there are no retail claims for Oregon customers" associated with the delivery of clean electricity.

The NW Energy Coalition and Renewable Northwest filed a joint brief taking no position on RECs directly but arguing that the Commission has discretion to address issues related to RECs beyond the DEQ accounting construct that is the basis for HB 2021's targets, which it notes does not currently include RECs. They point to the Commission's general broad supervisory powers

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[37] Green Energy Institute Opening Brief (July 24, 2023); Green Energy Institute Reply Brief (Aug. 21, 2023)
[38] ORS 469A.400(1)(a) (emphasis added by Green Energy Institute).

over utilities under their jurisdiction. They also point to HB 2021's goals which state in part "[i]t is the policy of the State of Oregon * * * [t]hat retail electric providers rely on nonemitting electricity in accordance with the clean energy targets set forth in section 3 of this 2021 Act." However, they stop short of recommending the Commission interpret the statute to require REC retirement.

CUB argues against the requirement that RECs be retired to demonstrate compliance with HB 2021. It cites to HB 2021's text stating that "[n]othing in sections 1 to 15 of this 2021 Act may be construed as establishing a standard that requires a retail electricity provider to track electricity to end use customers" and argues that "HB 2021's directive is unambiguous and the Legislature's intent is clear." CUB also points to several pieces of legislative history, including statements acknowledging that HB 2021 is emissions-based not REC-based, made by some parties that now argue RECs must be retired.

CUB notes that the Commission could consider whether it can restrict the use of RECs not needed for RPS purposes even if it finds that REC retirement is not required for HB 2021 purposes. It argues that due to "the Commission's broad and general authority [], as well as specific provisions within the existing * * * RPS, the Commission can place REC-related conditions on utilities for their compliance with Oregon-based voluntary customer programs and the RPS."

The Joint Utilities argue that RECs are not relevant to determining compliance with HB 2021's emissions reductions targets. The Joint Utilities rely on the language regarding electricity having the emissions attributes of the underlying generating resource and the fact that the statute directs DEQ, not the Commission, to determine baseline emissions levels and necessary reductions. The Joint Utilities note that they have been reporting emissions to DEQ since 2009 in the manner HB 2021 requires, without any issues concerning double counting of RECs. "[R]eporting actual emissions from the * * * electricity generated or purchased to serve end users in Oregon" does not claim renewable energy; regardless of the presence or absence of RECs, this reporting to DEQ is not and never has been, in their view, a double claim.

The Western Power Trading Forum (WPTF) argues that RECs need not be retired for compliance with HB 2021, because HB 2021 is clearly an emissions reduction program not a clean energy procurement program. WPTF asserts that HB 2021 can be a load-based emissions reduction program *without* requiring retirement of RECs, and in fact that relying on RECs may complicate rather than prevent double counting of emissions. It notes that RECs neither convey the emissions rate of the underlying resource nor are generated by all generating sources that may be used to demonstrate the emissions reductions required by HB 2021. It also argues that DEQ can use its existing framework, with improvements through coordination with organized electricity market operators, to avoid double counting emissions.

4. Resolution

We must determine how HB 2021 answers the following question: Must regulated entities hold and retire the RECs generated by the renewable electricity resources and market purchases included in their emissions reporting to DEQ for the PUC to conclude, in 2030, 2035, and 2040, that they have complied with HB 2021's emissions reductions requirements? The Legislature did not answer this question explicitly in the text of the statute, notwithstanding the clear significance of this issue and the presence of widely diverging opinions even among the stakeholders most engaged in the legislative process. We therefore are left to discern legislative intent according to the protocol set forth in Oregon law, beginning—and, in many cases, ending—with the text and context of the statute.[39]

We conclude that the text and context point unambiguously to the conclusion that compliance with HB 2021's emissions reductions need not be demonstrated with RECs. The statute is less helpful in guiding us to resolution of the broader issues that result from that conclusion, but we attempt to provide some implementation guidance surrounding the consequences for RECs and associated claims and programs.

5. HB 2021 and retirement of RECs

The text that most clearly addresses the question at hand is HB 2021 section 7, which states: "For the purposes of determining compliance with sections 1-15 of this 2021 Act, electricity shall have the emission attributes of the underlying generating resource." Although section 7 does not address RECs directly, it is difficult to identify a meaning or function of that sentence that is not related to RECs. Given the context provided by Oregon's RPS law, and its detailed treatment of RECs, both those still associated with the purchased electricity and those disaggregated from it., we presume legislative awareness that RECs may be unbundled from the underlying electricity to change the attributes of delivered electricity. Besides RECs, we are unaware of anything, in Oregon law or otherwise, that would impute emissions attributes to electricity that differ than those of the underlying generating resource. Therefore, we see no possible meaning or function for this sentence other than a legislative direction that the presence or absence of RECs should not be considered in determining emissions for HB 2021 compliance.[40]

Legislative history does not contradict our reading of the text. We are aware that, during the legislative process, a version of this provision of the bill was more explicit, adding the phrase "regardless of the disposition of the renewable energy certificate associated with the electricity."

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[39] *State v. Gaines*, 206 P.3d. 1042, 1050 (Or. 2009).

[40] A well-established maxim of statutory construction, codified in Oregon law, would have us give effect to every section of the statute. *See* ORS 174.10; *see also State v. Clemente-Perez*, 359 P.3d 232, 239 (2015).

We find no explanation in the legislative history for the deletion of this phrase. However, our primary task is to interpret the language of the statute as it exists, without resort to legislative history if the text and context are unambiguous.[41] Put simply, the deletion of the phrase does not change the remaining text's meaning and function; the text of the adopted legislation says in more general and implicit, but still unambiguous, terms what the deleted phrase stated directly.

In addition, immediately following the provisions establishing HB 2021's basic emissions reductions targets, the statute states that "[n]othing in [sections 1 to 15 of this 2021 Act] may be construed as establishing a standard that requires a retail electricity provider to track electricity to end use retail customers."[42] GEI argues that this provision was meant merely to make clear that individual electrons need not and cannot be tracked to particular end-use customers. We agree that this phrase could be read to prohibit reliance on instruments other than RECs to track electricity to specific delivery points.[43] However, in the context of the statute's statement that electricity has the attributes of the underlying generating resource and of an industry that often uses RECs as a proxy to track renewable electricity to end users, the provision reinforces our view that the drafters of HB 2021 did not intend to require use of RECs to track electricity to load.

In addition to these directly applicable provisions, the broader statutory context supports our interpretation. HB 2021 is not a renewable energy procurement program, in contrast to the RPS law. The RPS requires utilities to source electricity from specified technologies and retire RECs to demonstrate that they have complied.[44] HB 2021, by contrast, is emissions-focused and, importantly, explicitly assigns emissions accounting responsibility to DEQ.[45] Under that delegation and in the context of the enabling statute ORS (468A.280) that HB 2021 directly references, DEQ does not use RECs in its emissions accounting system, and RECs do not impact

[41] The Oregon Supreme Court has long found that "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 v. Gaines*, 206 P.3d. 1042, 1050 (Or. 2009) (quoting *U.S. v. American Trucking Ass'ns.*, 310 U.S. 534, 543–44, 60 S. Ct. 1059, 84 L Ed 1345 (1940)).

[42] ORS 469A.410(2).

[43] For example, E-Tags, also known as Requests for Interchange or Interchange Transaction Tags, are used to schedule interchange transactions in wholesale markets. See "Glossary of Terms Used in NERC Reliability Standards, Updated December 1, 2023" available at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf (accessed January 4, 2024).

[44] Were we to reach legislative history, it would be worth noting that Oregon chose not to follow the example of other states that explicitly used RECs for compliance with 100 percent clean energy programs. For example, Washington's greenhouse gas neutrality standard for the electricity sector, the Clean Electricity Transition Act (CETA), provides that greenhouse gas neutrality "must be verified by the retirement of renewable energy credits." 2019 Wa. Laws Ch. 288, § 4 (codified at RCW 19.405.040(1)(c)).

[45] ORS 469A.420(1). Statements cited in CUB's brief, at page 15, demonstrate awareness of the Washington law's REC requirement during the Oregon legislative process.

the emissions factor for a generator.[46] Although HB 2021 creates new regulatory implications for the emissions that entities have reported to DEQ since at least 2010, it does not fundamentally change the claims associated with reporting emissions to DEQ. Nor does HB 2021 require changes in DEQ's emissions program, instead relying on it as an existing foundation. The clear contrast between the compliance systems established for the RPS and HB 2021 reinforces our textual conclusion that we should look to DEQ's emissions reporting structure and not to the presence of RECs to determine emissions for compliance purposes.

For the above reasons, we interpret the text and context of HB 2021—including its direct statements on the subject, its emissions framework standing in contrast to the REC-based RPS, and its direction to rely on DEQ's existing emissions accounting system—to be an unambiguous expression of legislative intent not to require RECs to demonstrate compliance with emission reduction requirements.

We are aware that HB 2021 refers in several places to retail electricity consumers and identifies covered emissions as those "associated with the electricity sold to retail electricity consumers as reported under ORS 468A.280."[47] We understand that defining a scope of covered emissions that is not purely geographic creates a source of ambiguity, suggesting either that electricity *sales* must be emissions-free or that the emissions must be eliminated from the *sources* of electricity that are used to serve retail load. However, in the context of section 7 and DEQ's existing system under ORS 468A.280, the phrase can be read simply to refer to emissions from the sources of electricity reported to DEQ, whose accounting framework isolates Oregon's electric emissions from the regional grid in part based on the amount of load an electricity supplier serves in Oregon.

6. Characterizing HB 2021 and its implications for REC claims

Having interpreted HB 2021 not to require retirement of RECs, we will address requests to characterize HB 2021 as "generation-based." GEI and CRS ask us to clarify that entities subject to HB 2021 who do not hold and retire RECs may not claim to have delivered emissions-free or clean energy to their retail customers. By characterizing HB 2021 as generation-based, GEI and CRS argue, we can limit claims that may be implied by reporting emissions from sources procured to serve retail load and thereby help avoid double counting.

[46] "For purposes of compliance with Oregon's RPS, a bundled REC for wind or solar power (which has zero emissions) is identical to a bundled REC for electricity produced from municipal solid waste combustion (which does not have zero emissions)." ODOE Comments at 3 (July 24, 2023).

[47] *See, e.g.,* ORS 469A.400(1) (HB 2021 Section 1) (defining baseline emissions level as emissions "associated with the electricity sold to retail electricity consumers"); ORS 469A.405 (HB 2021 Section 2) (stating policy to eliminate GHG emissions "associated with serving Oregon retail electricity consumers").

Oregon law does not use the terms "load-based" or "generation-based." These are terms and approaches that have developed through the cooperative efforts of many entities nationally and internationally to clarify greenhouse gas emissions reporting and attribution across the public and private sectors and in the context of many differing electricity market models.[48] We are not confident that every emission regulatory system has clearly aligned with one or the other category, as state legislatures and agencies adopt varied approaches to define the bounds of the regulations they are creating. In a regional electricity system in which utilities and electricity service suppliers generate electricity, make market purchases and sales from a broad geographic footprint, and serve load in multiple states, states must develop mechanisms to identify the electricity subject to their emissions regulatory programs.

Advocates argue any system that diverges from a solely geographic scope must be load-based. DEQ's program rules center on emissions of a generation source but they also ask reporting entities to use measures related to retail load, market sales, and cost allocation to Oregon retail customers to isolate the emissions that DEQ assigns to Oregon. As a result, they utilize market emissions data to assign emissions to some reported electricity. [49] Although we do not believe the use of such allocation factors to identify Oregon's emissions makes DEQ's framework inherently load-based, we also hesitate to firmly characterize DEQ's system, and thereby HB 2021, as generation-based. This hesitation comes in part from the absence of these characterizations in Oregon law and from deference to DEQ's primary role in emissions accounting under HB 2021, but also in part because we would not want a firm definition to complicate future evolution of DEQ's emissions accounting regime. We favor WPTF's view that DEQ's framework is appropriate, but also should continue to evolve in cooperation with the expansion of organized energy markets to avoid double counting of emissions.

As a practical matter, we observe that the DEQ reporting program and Oregon RPS program have co-existed for more than a decade. Utilities' emissions reporting to DEQ has not historically created concerns regarding claims, at least not concerns that have arisen, to our knowledge, during the PUC oversight of Oregon REC-based programs. Likewise, DEQ data has been used in policy settings such as the Oregon Global Warming Commission's biennial report to the Legislature on global warming in the state.[50] Until the passage of HB 2021, we are not aware that stakeholders have raised the issue of double claims. Similarly, DEQ has historically utilized the PacifiCorp multi-state cost allocation approach to define the scope of emissions PacifiCorp must report.[51] In the existing, approved cost allocation, Oregon customers are

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[48] CRS Comments at 1-3 (July 24, 2023).

[49] Likewise, Washington and California go beyond a strictly geographic definition of emissions in their generation-based cap and trade systems in order to identify the emissions content of electricity imported into the state.

[50] *See* 2023 Report to the Legislature https://olis.oregonlegislature.gov/liz/2023I1/Downloads/CommitteeMeetingDocument/277144.

[51] OAR 340-215-0120(6)(c) ("DEQ will calculate multi-jurisdictional utility system emission factors consistent with a cost allocation methodology approved by the Oregon Public Utility Commission using the following equation:")

allocated a slice of the PacifiCorp generation fleet—emitting and non-emitting—that is proportional to Oregon load even while those generators are located as far away as Colorado.[52] RECs have never been transferred as part of allocating non-emitting generation to Oregon customers in the cost allocation or in DEQ's resulting emissions reporting. The emissions reporting approach, while not defined by specific geographic boundaries, has been implemented as though it is generation-based, counting actual emissions from the dispatch of PacifiCorp's fleet.

Despite our hesitation to firmly assign a "generation-based" label to HB 2021, we do find it appropriate to clarify our understanding of the implications of emissions reporting to DEQ. HB 2021 requires us to consider "the emission attributes of the underlying generating resource" and, as such, emissions reported for compliance with HB 2021 can only reflect the underlying generating resource. We do not understand statements about the underlying generating resource to undermine the integrity of RECs associated with the reported electricity or to constitute a claim to have delivered renewable energy to an end user.

At the same time, we recognize that purchasers will need clear information to determine whether RECs associated with electricity reported to DEQ will meet their needs. Voluntary purchasers have varied and evolving priorities and REC-based state compliance programs have varied rules; either or both may be complicated by HB 2021. If an entity subject to HB 2021 compliance sells RECs not needed to comply with Oregon's RPS, we will hold that entity responsible for being clear that it will continue reporting the underlying renewable generation as emission-free to DEQ and that such reporting will now be the foundation for HB 2021 compliance. Sellers must avoid making delivery claims properly belonging to the REC holder. However, we are reluctant to say that no market can exist for RECs associated with electricity used for HB 2021 compliance when accompanied by honest representations about HB 2021 emissions reporting, and therefore we do not prohibit the utilities from selling RECs associated with HB 2021 compliance. Because we find it unnecessary to place restrictions on selling RECs, we do not reach the question of our authority to do so.

7. Tools to maintain environmental integrity and advance the public interest

Those who encourage us to require retirement of RECs for compliance view this outcome as important to preserving HB 2021's environmental integrity. Accordingly, they urge us to use our discretion under the broad public interest and HB 2021's policy statements to implement HB 2021 as a load-based program and require REC retirement to maximize the law's environmental impact. Although we sincerely appreciate concerns about the environmental impact of state

[52] *See* Order No. 20-024 (adopting PacifiCorp's 2020 Inter-Jurisdictional Allocation Protocol to update the company's inter-jurisdictional allocation methodology.)

policy, we are not in a position to skew our statutory analysis of HB 2021's compliance requirements to address those concerns.

Fortunately, we have tools available to us to address these issues. One example is our broad authority to oversee utility planning, both under the public interest considerations relevant to clean energy plans under HB 2021 and under the general powers under which we adopted IRP requirements. In other words, when it comes to modeling GHG emissions and the cost and risk of emissions reductions strategies, we are not limited to the minimum requirements of emissions accounting for HB 2021 compliance. For decades, this Commission has required rigorous cost and risk analysis, including analysis of future regulatory risks. We may need additional information and different types of modeling to understand the risks that the state's emissions accounting framework may evolve over time or even that new climate policies could be adopted. Moreover, public interest considerations under HB 2021 may lead us to require emissions modeling and analysis that gives us insight into environmental justice implications.

Another example of our opportunity to address public interest considerations generally and the environmental integrity of HB 2021 specifically is our role in informing and influencing organized market development, a forum in which we are paying explicit attention to emissions leakage and double counting in the complex context of neighboring states that have implemented carbon allowance requirements and others that have no emissions limitations.[53] We intend to continue to work with DEQ and potential market operators to advocate that rules for deeming electricity dispatched by an organized market evolve fairly, with an understanding of tradeoffs around attribution, leakage, double counting, and other considerations. We expect frameworks for emissions accounting under HB 2021 will need to remain flexible to evolve, because information provided by market operators and other state policies embedded in the market will also evolve.

Finally, as HB 2021 compliance deadlines approach, we will work to ensure that accurate information is provided to Oregon-regulated voluntary purchasing programs. Although, again, we do not understand emissions reporting to DEQ to represent a claim to the environmental attributes carried by the REC, we will remain receptive to arguments that voluntary purchasers'

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[53] Oregon entities have participated in the California Independent System Operator (CAISO) Energy Imbalance Market since 2014 and PacifiCorp has announced its intention to deepen integration with that dispatch approach through the Extended Day-Ahead Market. The California Air Resources Board (CARB) has developed its cap-and-trade program to apply to in-state generators (a geographic boundary) and imported electricity (a load centered definition). CARB's program, and particularly tracking of imported electricity, operates in light of the trade and dispatch of electricity in the CAISO market. DEQ's approach, focused on the emissions of the underlying generator, allows for the electricity generated in Oregon and exported to California under the CARB cap-and-trade program to be represented in a consistent manner between the states.

needs for regulatory surplus are not met by RECs associated with electricity procured by entities subject to HB 2021.[54]

We understand that emissions accounting and the role of RECs is a complex and important issue with which we will continue to engage, even after having reached our conclusion that retirement of RECs is not required for HB 2021 compliance.

B. Issue I(a)(2): HB 2021 Section 5(2) public interest factors

HB 2021 requires us to acknowledge CEPs if we find the CEP to be in the public interest and consistent with HB 2021's clean energy targets.[55] HB 2021 also provides a list of public interest factors we are to consider in determining whether a CEP is in the public interest, as well as the discretion to consider other relevant factors in making such a determination.[56] The specifically enumerated factors we are to consider include:

> (1) Any reduction in greenhouse gas emissions that is expected through the plan, and any related environmental or health benefits;
> (2) The economic and technical feasibility of the plan;
> (3) The effect of the plan on the reliability and resiliency of the electric system;
> (4) Availability of federal incentives; and
> (5) Costs and risks to the customers.[57]

Our scoping order asked whether we should provide guidance on our interpretation of any of the HB 2021 section 5(2) public interest factors or whether we should pre-determine other relevant factors as authorized by HB 2021 section 5(2)(f). In our scoping order, we indicated that we were unlikely to further explicate these factors until after we had gained experience applying the public interest standard to specific facts in our initial CEP dockets. We note that there has been ample discussion of these factors in our pending CEP dockets. Although we provide some observations here, including recognizing the central role of environmental justice and energy burden, we largely continue to favor a case-by-case application of HB 2021 section 5(2).

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[54] Voluntary purchasers often seek to ensure their actions are additional to any existing regulatory requirements or other actions that would take place under the normal course of business. One aspect of this is described as "regulatory surplus". For example, in a state with a carbon allowance regime, a purchaser may pair a REC with retiring a carbon allowance, effectively reducing the available carbon allowances and tightening the carbon emissions cap on emitting entities. Without this action, the voluntary procurement of the renewable energy alone does not reduce the allowed carbon emissions and so does not go beyond the established regulatory trajectory.
[55] ORS 469A.420(2).
[56] *Id*.
[57] *Id*.

1. Positions of Parties and Commenters

The parties briefing this issue argued either that no additional guidance was needed or that several HB 2021 section 5(2) factors required guidance and that the Commission should pre-determine other relevant factors at this stage.

PGE, PacifiCorp, and CUB argue that no additional guidance on the section 5(2) factors is needed. The joint utilities argue that the Commission has extensive experience evaluating whether something is in the public interest and that no additional guidance is needed now. However, the joint utilities also argue that, should the Commission provide additional guidance, such guidance should only be applicable to future CEPs and not currently filed CEPs.

CUB elaborates that whether something is in the public interest is inherently a fact-based determination specific to an individual CEP. CUB explains that the Legislature provided several public interest factors the Commission must consider in evaluating a CEP but granted the Commission further discretion to consider additional factors if needed. CUB also explains that what is in the public interest can shift over time and, as a result, being overly prescriptive now could be counter to the Commission's responsibility to protect the public interest.

Several groups argued that additional guidance on the section 5(2) factors was needed. Climate Solutions argued that additional guidance on how the Commission will balance emissions reductions and the public interest is needed, noting, for example, that economic and technical feasibility is about reliability and affordability. The Community Renewable Energy Coalition (CREA) argues that economic and technical feasibility should consider transmission constraints and that cost overruns are likely.

Renewable Northwest and NW Energy Coalition argue that we should adopt guidance explaining that CEPs should be realistic and implementable, not speculative, and that both supply side and demand side incentives should be analyzed. They also argue that Community Benefits and Impacts (CBIs) should be a key factor in determining whether a CEP is in the public interest.

NewSun Energy argues that we must provide early and clear guidance on what factors we will use in determining whether a CEP is in the public interest. NewSun urges us to define the public interest broadly and include the public generally and communities outside a given utility's service territory, including communities that might be located near energy generating facilities. NewSun Energy also argues that we should define economic and technical feasibility to mean that a utility's resource and transmission assumptions in a CEP can come online within the time specified and that cost estimates are within reason.

OSSIA asserts we should define technical feasibility as requiring a CEP to rely on realistic assumptions and consider the uncertainty and risks around interconnection, permitting, and development timelines, and urges that utilities should plan for contingencies in the event of delay. OSSIA further asks us to articulate additional factors we will consider, including reducing impacts on environmental justice communities, impacts on communities not in a utility's service territory, resiliency, and direct benefits to communities.

Sierra Club, Rogue Climate, Columbia Riverkeeper, and Coalition of Communities of Color provided an extensive list of factors it would like us to adopt, including factors related to Tribal interests and treaty rights, natural resources, community energy resiliency, burdens to environmental justice communities, public health, public participation, and RECs.

CRITFC provided us with several definitions for the articulated public interest factors, including that we consider several issues of importance to Tribal communities, such as impacts on first foods, impacts on salmon in the Columbia River, and renewable resource siting and grid integration measures that recognizes and respects Tribal interests, amongst others.

Pine Gate Renewables urges us to use HB 2021's policy statements as a basis for additional factors we will consider in determining whether a CEP is in the public interest.

Several organizations, including Multnomah County Office of Sustainability, Verde, Oregon Just Transition Alliance, Rogue Climate, NW Energy Coalition, and Coalition of Communities of Color provided us with an extensive list of recommendations on additional guidance we should issue for HB 2021's public interest factors, as well as a list of other factors we should consider related to energy justice, procedural justice, and distributional justice, among others.

2. Resolution

We conclude that HB 2021 section 5(2)'s public interest factors are broad and deliberately provided us with extensive discretion to consider an expansive array of factors in determining, in a fact-specific scenario, what is in the public interest. We decline at this time to articulate any specific additional factors we will explicitly consider in determining whether a CEP is in the public interest under HB 2021 section 5(2)(f).

We are asked in many different situations to make public interest determinations after considering a variety of factors, and our experience leads us to the conclusion that providing greater specificity as to the definitions of the articulated section 5(2) public interest factors could have unintended consequences and unintentionally limit our ability to analyze a given CEP. Because each CEP is unique and based on specific facts applicable to only that CEP, we do not want to unintentionally limit our ability to analyze a given CEP or signal that certain factors will be more important to us than others by explicitly pre-determining such factors at this stage. Our decision today is not intended to limit the universe of items we will ask electricity companies to analyze and explain, but rather to ensure we can obtain extensive analysis on a broad array of issues, including issues we are unable to anticipate today or that have not yet emerged as being relevant. We also suspect that adding factors would make it more difficult, not less difficult, to focus stakeholder attention in review of CEPs.

At the same time, we received persuasive advocacy in favor of adding impacts on environmental justice and energy-burdened communities as a specific factor, as well as extensive comments on the role and meaning of "economic and technical feasibility" in evaluating whether a CEP is in the public interest. Without limiting our analysis of pending CEPs, we offer some responsive observations that may inform our review of CEPs and our future development of revised IRP and CEP guidelines.

a. Impacts on environmental justice and energy-burdened communities

Our public interest review of CEPs will consider impacts on environmental justice and energy-burdened communities because we see such issues as central to the public interest the law seeks to capture. Not only does ORS 182.545(1) already require that we consider the effects of our actions on environmental justice issues, but the policy statements in HB 2021 section 2 emphasize workforce equity, tribal engagement, and minimizing burdens for environmental justice communities. Although policy statements are not operative provisions of the law, we certainly do not intend to overlook the Legislature's explicit policy statements as relevant elements of the public interest when applying a non-exclusive list of public interest factors.

Furthermore, the enumerated public interest factors require us to consider "economic * * * feasibility" and "costs and risks to the customers," which we note requires economic and rate impact considerations regardless of whether section 10's cost cap process has been initiated. We have emphasized previously that affordability analysis requires us to consider differential impacts on energy burdened communities, and such impacts will continue to be part of our analysis of economic feasibility and customer costs and risks.

We expect that Staff, utilities, stakeholders, and members of the public will offer analysis and comment on environmental justice and energy burden in CEPs, and we encourage specific and practical suggestions for how planning can progress in these areas in each CEP cycle. We also expect that future revisions to IRP and CEP guidelines will make economic and rate impact considerations—including for energy-burdened communities—more visible in the tradeoffs among portfolios and actions.

b. Economic and technical feasibility

Several parties urge us to define more specifically HB 2021's "economic and technical feasibility" public interest consideration. This advocacy represents a good example of why we generally hesitate to narrow the focus of these public interest considerations, and instead favor fact-specific application; at the same time, this advocacy gives us a good opportunity to note that many of the themes parties want us to endorse can be found in guidance we already issued in docket UM 2225, and will develop further as we consider new IRP and CEP rules.

The core concern expressed by parties advancing this position is that CEPs will be overly speculative; they will rely on unrealistic assumptions about the cost and availability of resources and delivery infrastructure, and will fail to explore risks, develop contingency plans, or articulate the circumstances and timelines triggering a pivot to an alternative strategy. We share this concern, which is why in Order No. 22-446 we endorsed Staff's recommendation guiding utilities to consider several high-level planning questions as part of their CEPs, including the following:

- What low regrets near term actions does the utility expect to perform relatively well, if implemented, regardless of future uncertainties in technology, demand, and regional developments?
- What near term actions that the utility considered might have large negative long-term consequences (in terms of cost, risk, GHG emissions, or community impacts or benefits) under one or more future technology, demand, or regional development scenarios?
- What are the critical junctures at which the utility's plan would materially change and what indicators will the utility use to identify whether those junctures are approaching?
- What are the critical dependencies for the utility to successfully execute its long-term plan?
- What critical barriers need to be addressed to implement the utility's long-term plan? Which of these barriers can be addressed by the utility or the Commission and which of these barriers are out of the utility's or the Commission's control?[58]

Staff has carried these questions forward to guide its review of initial CEPs.[59] Staff and parties have presented, in those dockets, various specific criticisms of the utilities' cost and availability

[58] Order No. 22-446 at 1, Appendix A at 16 (Nov. 14, 2022).
[59] *See In the Matter of Portland General Electric's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Report (Dec. 14, 2023); *In the Matter of PacifiCorp's dba Pacific Power's 2023 Integrated Resource Plan*, Docket No. LC 82, Staff's Round 1 Comments (Oct. 25, 2023).

assumptions, their timing estimates, and the quality of their contingency planning. While we look forward to engaging these issues in utility-specific dockets and believe that some of the suggestions received here will be helpful in considering future updates to IRP and CEP guidelines,[60] we do wish to caution against the narrowest implication that uncertainties about the future should always lead utilities to maximize their commitment to the resources most readily available today.

The statute's direction is to consider "economic and technical feasibility" together; this phrase, in itself, introduces a balancing of tradeoffs, even before considering other public interest factors. Overcommitment to resources that may be relatively more available today but may be relatively more expensive and less valuable to meeting reliability and GHG emission reduction needs in the long-term, may not be an "economically feasible" plan. Though today some parties perceive utilities to be delaying action in favor of unrealistic future solutions, there may be times when economic feasibility favors waiting for new technology to emerge. For example, in recent IRP cycles, we have struggled to understand the future tradeoffs associated with large-scale near-term commitments proposed by utilities and have looked, as Staff's first question articulates, for "low regrets near term actions * * * expect[ed] to perform relatively well, if implemented, regardless of future uncertainties." We decline to react to today's factual context by overemphasizing technical feasibility in our guidance, which could inappropriately narrow how we apply the full statutory phrase to circumstances we are unable to anticipate today.

To be clear, we do not intend for this observation to excuse insufficient exploration of risks and uncertainties, alternative strategies, or contingencies. We simply note that, when weighing economic and technical feasibility, both are important to the public interest.

C. Issue I(a)(3): HB 2021 policy statements

As with many laws, HB 2021 includes statements articulating the "policy of the State of Oregon."[61] One of HB 2021's four policy statements explains the State's policy as follows:

> That electricity generated in a manner that produces zero greenhouse gas emissions also be generated, to the maximum extent practicable, in a manner that provides additional direct benefits to communities in this state in the forms of creating and sustaining meaningful living wage jobs, promoting workforce equity and increasing energy security and resiliency[.][62]

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[60] Specifically, we endorse further development of standards and processes to guide the "interplay between established and emerging resources," NW Energy Coalition & Renewable Northwest Opening Brief at 9 (July 24, 2023), and the cost and availability assumptions and modeling treatment of "non-commercialized resources," Sierra Club *et al*. Opening Brief at 6-7 (July 24, 2023).
[61] ORS 469A.405.
[62] ORS 469A.405(2).

Our scoping order asked whether this policy statement requires that utilities prefer in-state resources, and if not, what relevance we give to this policy statement. We provided our preliminary conclusions that HB 2021 does not assert a requirement or preference for in-state resources but does favor maximizing community and resiliency benefits in carrying out the operative provisions of the law.

We maintain the conclusion that HB 2021 does not assert a requirement or preference for in-state resources, because the Legislature did not include any such language in HB 2021's operative provisions. Nonetheless, we intend to seek information about direct benefits to communities in Oregon so that we can determine where we may have opportunities to further this policy statement that are practical, impactful, and consistent with state and federal law.

1. Positions of Parties and Commenters

The parties largely agree that HB 2021's policy statements inform and provide context for the law's operative provisions, but do not create independent legal obligations. In particular, the parties generally agree that HB 2021 section 2(2) does not create any kind of in-state preference, however, the parties disagree on the extent to which the policy statements inform our review of CEPs.

PGE and PacifiCorp argue the section 2 policy statements must be balanced against competing Oregon energy and climate policies and may be difficult to harmonize with other statutes.

CUB explains that the section 2 policy statements can help inform our interpretation of unclear statutory provisions and that any HB 2021 rulemaking proceedings consider the law's policy statements.

Climate Solutions argues that several HB 2021 provisions relate to the development of Oregon-based projects, which is a strong inference that the Legislature foresaw significant development of such Oregon-based projects.

NewSun Energy explains it is concerned Oregon electric companies will develop renewable energy projects outside Oregon and claim benefits inside Oregon. NewSun believes we can give weight to the section 2 policy statements without establishing a requirement for in-state generation by requiring electric companies to demonstrate how their CEPs meet the section 2 policy goals and to affirmatively demonstrate that renewable energy generated out-of-state is delivered to Oregon consumers through transaction tagging.

NW Energy Coalition and Renewable NW explain there cannot be an in-state preference but suggest incorporating the section 2 policy statements as considerations for what is in the public interest as we review CEPs. They explain we could ask Oregon electric companies to explain how a CEP will result in meaningful living wage jobs, workforce equity, and energy security and resiliency for the communities they serve.

Sierra Club, Rogue Climate, Columbia Riverkeeper, and Coalition of Communities of Color argue that the section 2 policy statements cannot be disregarded and are relevant to determining whether a CEP is in the public interest.

2. Resolution

We affirm our scoping order's preliminary determination that HB 2021 does not include any explicit requirement for in-state resources, nor does it include any operative provision that requires regulated entities to produce in-state benefits. However, HB 2021's policy statements do clearly favor maximizing direct benefits to communities in Oregon and we do not intend to ignore these statements when reviewing CEPs. Indeed, Section 4(4)(d) of HB 2021 requires utility CEPs to "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy,"[63] a term that HB 2021 defines to require a "direct benefit to a particular community" or to "[r]esult in increased resiliency or community stability, local jobs, economic development or direct energy cost savings to families and small businesses."[64]

Although we are not, as yet, certain exactly whether or how direct benefits to Oregon communities could impact our decisions in the area of utility resource strategy or procurement, we are persuaded that having more information about direct benefits to Oregon communities is a necessary first step. We intend, in our upcoming consideration of planning and procurement processes, to examine the most practical and impactful ways to gather information about direct benefits to communities in Oregon. In fact, this discussion is well underway through the development of community benefit indicators in our ongoing CEP dockets, and as these indicators continue to develop, we will consider ways to extend or adapt them to RFPs as well.[65]

We emphasize, however, that the tradeoffs associated with resource planning and procurement are complex. For one thing, resource planning through IRPs and CEPs is best suited to comparing and contrasting resource strategies broadly; while there could be more or less direct

[63] ORS 469A.415(4)(d).
[64] ORS 469A.400(2)(a), (b).
[65] In Docket No. LC 80, PUC Staff recommended we require PGE to develop informational and portfolio CBIs before its next IRP/CEP update and expressed an intention to ask utilities to make proposals for using community benefit indicators in their next utility scale RFPs. *In the Matter of Portland General Electric's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Report at 22, 29 (Dec. 14, 2023).

benefits to different strategies, it is at the resource procurement stage that benefits and impacts emerge most directly through specific resource selections. Moreover, it is possible that an Oregon-based project could simultaneously provide localized community benefits while negatively impacting Oregon environmental justice communities, just as it is possible that a project located outside Oregon could offer significant direct resiliency and cost benefits to Oregonians while negatively impacting environmental justice communities elsewhere. Finally, strategies or resource selections with large community benefits that impose significant incremental resource costs may not be appropriate given the impact those costs may have on energy-burdened ratepayers and the costs and risks to customers overall. Careful consideration of these tradeoffs is important and, to put it simply, we do not agree that in-state resource location is always a proxy for maximizing direct benefits to Oregon communities.

We also disagree that requiring regulated utilities and other suppliers to produce tags demonstrating transfer of electricity to an Oregon sink would increase direct benefits to Oregonians.[66] Virtually all of Oregon's electric service comes from grid-connected generating facilities, and Oregon relies on the diversity and stability of the entire Western grid to maintain reliability and affordability. Grid-connected facilities located outside Oregon contribute to reliable service for Oregon electricity customers and to reducing GHG emissions on the grid, and facilities located inside Oregon do not serve Oregon customers exclusively. There may be resiliency benefits to in-state resources and resource strategies that are worthwhile to consider, but those must be based on reliability and resiliency analysis or related valuation methodologies, not assumed based solely on geographic location or the presence of specific electricity market transaction receipts.

D. Issue I(a)(4): Determining continual progress

HB 2021 section 4(4) requires that CEPs "[d]emonstrate the electric company is making continual progress within the planning period towards meeting the clean energy targets * * * including demonstrating a projected reduction of annual greenhouse gas emissions."[67] Section 4(6) requires the PUC to also "ensure that an electric company demonstrates continual progress * * * and is taking actions as soon as practicable that facilitate rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers."[68]

Our scoping order asked what procedural approach we should take to carry out HB 2021 section 4(6). We conclude that our existing CEP and IRP review processes are appropriate for making regular determinations that utilities are achieving continual progress at an appropriate pace of

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[66] Moreover, as discussed above, HB 2021 prohibits a requirement to track electricity to end consumers. *See* ORS 469A.410(2).
[67] ORS 469A.415(4)(e).
[68] ORS 469A.415(6).

action under HB 2021 section 4(6). However, we could initiate additional processes if we need to direct utility action.

Several parties have asked us to address whether our continual progress determinations will be made in final orders subject to judicial review. We conclude that they will, but we limit our conclusion to continual progress determinations under HB 2021 section 4(6).

1. Background

Three HB 2021 responsibilities assigned to the PUC are relevant to this issue: First, section 5(2) requires the PUC to acknowledge utility-filed CEPs if they are consistent with the clean energy targets and in the public interest. Second, the PUC must assess continual progress, both for utilities and for electricity service suppliers (ESSs); section 4(6)[69] requires the PUC to "ensure" that utilities are making continual progress and taking actions as soon as practicable, and section 5(3)(d)[70] requires the PUC to "determin[e]" whether ESSs are "making continual and reasonable progress" toward the targets. Third, the PUC must determine compliance pursuant to section 5(4)(b), determining whether utilities and ESSs have met the clean energy targets that begin in 2030.

HB 2021 builds the requirement for utility CEPs onto the foundation of utility IRPs, requiring in section 4(3)(a) that CEPs be integrated with or filed promptly after utility IRPs. IRPs are a long-time PUC requirement, not required by nor previously referenced in statute. HB 2021 does not establish a statutory cadence for CEP filings, only requiring them to be linked to IRPs. The PUC's rules generally require an IRP update to be filed within one year of the previous IRPs acknowledgment and the next IRP within two years of acknowledgment,[71] a practice the PUC has provisionally extended to CEPs in OAR 860-027-0400. This rule further provides that, if a utility seeks to extend these deadlines for CEPs, the utility "must explain how it will make continual progress * * * during the period of extension."[72] Intervening, and now commonly overlapping, with these planning cycles are utility requests for proposals (RFPs), which for major resources generally follow a process set forth in PUC rules.[73]

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[69] *Id*.
[70] ORS 469A.420(3)(d).
[71] The term "acknowledgment" in utility planning is referential to the ultimate determination of prudence in a rate case (which may be filed for recovery of costs in rates only after a utility takes action), and generally signals that the Commission finds the plan reasonable at the time without prejudging its ultimate determination of prudence. With iterative planning filings creating a near-continuous cycle of plan development and redevelopment, including during procurement processes (which, for major resources as defined in OAR 860-089-0100(1)(a), must themselves be overseen by the PUC), and industry and market circumstances evolving up until the moment a utility takes action, the Commission reserves its final decisions for rate cases. Several circuit courts have agreed that PUC IRP and RFP acknowledgments are not final orders subject to judicial review, but no appellate court has yet addressed the question.
[72] OAR 860-027-0400(3).
[73] OAR 860-089-0010, *et seq*.

Although we have adopted provisional rules for IRP and CEP filing cycles,[74] we have not yet detailed a process for determining compliance with the clean energy targets for utilities and ESSs under section 5(4)(b). Compliance requirements begin in 2030, and emissions data would not be available from DEQ for the PUC to rely on to make a compliance determination until sometime in 2031.[75]

2. Positions of Parties and Commenters

PGE and PacifiCorp argue that our duty to ensure continual progress is limited to reviewing individual IRP/CEPs and should not require separate progress reports or compliance filings. The joint utilities urge us to not require annual filings due to the increased administrative burden of such work in contrast with the incremental value provided by such a filing.

Some groups, including NewSun and OSSIA, argue that any determination on continual progress must be in a final order subject to judicial review.

Climate Solutions asserts a continual progress determination must be both forward and backward looking, and generally demonstrate a linear reduction in GHG emissions. NewSun Energy argues that no IRP, CEP, or RFP be acknowledged or approved unless a utility affirmatively shows it is on track to acquire resources in the near-term to ensure compliance in the long-term.

NW Energy Coalition and Renewable NW argue we can rely on existing processes, including CEP review processes, to assess continual progress, however, also suggest we consider requiring annual updates during the beginning years of HB 2021.

Sierra Club, Rogue Climate, Columbia Riverkeeper, and Coalition of Communities of Color argue we can first rely on CEP review processes to determine continual progress. They argue such a determination should be both forward and backward looking and that we should use the biennial reports of Community Benefits and Impacts Advisory Groups to determine if the process is working. They also urge the Commission to consider its broader authority to ensure continual progress.

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[74] *See* OAR 860-027-0400.

[75] In response to parties' requests, we have confirmed that the clean energy targets are binding and that we will establish processes for making compliance determinations (and, potentially, consequences for non-compliance) as we determine appropriate to our resources and priorities. Order No. 23-061 at 10.

3. Resolution

We conclude that HB 2021 gives the Commission significant discretion as to the meaning of "continual progress" and related phrases, how frequently and by what processes they should be assessed, and how we use our authority to "ensure" continual progress by utilities.

Throughout the PUC's HB 2021 implementation process, some participants have urged us to adopt a firm definition of continual progress and related phrases ("continual progress within the planning period towards meeting the clean energy targets" and "taking actions as soon as practicable that facilitate rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers").[76] As a matter of statutory interpretation, we note that the Legislature neither mandated continual progress targets, nor further defined the phrases in question, and used words (like "practicable" and "reasonable costs") that suggest matters traditionally left to the PUC's discretion based on expert knowledge of the electricity industry and ratemaking. We have, thus far, generally agreed with PUC Staff's recommended guidance for interpreting these phrases in advance of the first utility CEP filings, recognizing that additional implementation steps—including rulemaking—are yet to come.[77]

Here, we confirm our intention not to define "continual progress * * * toward meeting the clean energy targets" to require utilities to pursue a linear trajectory of expected emissions reductions. Nor do we intend to assess continual progress solely or even primarily on the basis of whether emissions have declined year-over-year based on actual emissions reported to DEQ.[78] Adopting firm definitions like those proposed would prevent us from giving meaning to the full phrases in HB 2021 section 4(6), which require us to understand tradeoffs around practicability, emissions reductions, and costs. These tradeoffs are dependent on the data and perspectives developed in the planning process. We cannot effectively make the assessment required by Section 4(6) in

[76] *See*, e.g., Order No. 23-061 at 5 (Applicants for reconsideration urging us to require a linear trajectory of GHG emissions reductions), 6 (NW Energy Coalition urging a definition that enables the Commission to determine whether the emissions targets can be achieved) (Feb. 24, 2023).
[77] *See* Order No. 22-390 at Appendix A, 15 ("While Staff believes that some level of year-over-year emissions reduction in the Preferred Portfolio is a minimum expectation, Staff's leans on the robust weighing of costs and risks engrained in the IRP to determine what constitutes continual progress beyond that."); Order No. 23-060 at Appendix A, 6 (adopting revised IRP guideline for first CEP filing that states: "In testing different paces of GHG emissions reductions, all portfolios should, at minimum, demonstrate year-over-year emissions reductions on an expected basis.").
[78] Nothing we find in the text or context of HB 2021 suggests that we are meant to determine "continual progress" based on actual emissions reductions achieved before the compliance deadline, though reports of actual emissions performance will be helpful evidence to evaluate whether additional or different forward-looking actions are needed. In fact, the context of section 4(6) points us away from a primary focus on backward-looking emissions performance, defining the concept of "continual progress" with reference to the requirement in section 4(4)(e) that utility CEPs demonstrate "continual progress within the planning period," in a manner that "includes demonstrating a *projected* reduction" of annual emissions (emphasis added).

isolation from industry and market circumstances that are constantly evolving and presented regularly in utility planning. In addition, we must be prepared to account for the various exceptions to compliance set forth in HB 2021. Thus, we lean on the robust weighing of costs, risks, and forecasted emissions reductions trajectories that will occur in the IRP/CEP planning process to determine whether utility actions within the planning period are sufficient to constitute continual progress toward meeting the targets.[79] In addition to assessing the forward-looking actions identified in the planning process, we also will evaluate whether utilities are carrying out the actions in their plans (or justifying modifications to those actions). Our rules require utilities to file, within one year of IRP or CEP acknowledgment, an update assessing their progress, including information on emissions reports from DEQ.[80]

Our conclusion that the assessment HB 2021 section 4(6) requires us to make is integrally connected to the IRP and CEP planning processes leads us to the further conclusion that we will use IRP/CEP review processes and their timelines to assess whether utilities are making "continual progress" and "taking actions as soon as practicable." In other words, we will evaluate continual progress regularly in connection with our proceedings for acknowledgment of IRPs and CEPs and review of IRP and CEP updates.

One procedural complication with making continual progress determinations in the same proceedings as IRP and CEP acknowledgment decisions involves the finality of these distinct determinations. We have treated IRP acknowledgment orders as non-final decisions whose appeal would lead to piecemeal review of annually evolving plans in which our acknowledgment is preliminary to a final decision in a rate case, and this reasoning may extend to our highly intertwined CEP acknowledgment decisions. However, we understand that the purpose of requiring continual progress is to ensure utility action during the years before compliance with the relevant target is required, and that a lack of continual progress may not be capable of remedy solely at the time of that eventual compliance determination. Therefore, we intend for continual progress determinations to be made as final decisions subject to judicial review. This means that we intend to make separate determinations, in separate orders entered in the same docket, for continual progress and acknowledgment, but we will rely on the same record.

If we determine, in an IRP/CEP docket, that the continual progress required by HB 2021 has not been demonstrated, we may also initiate additional proceedings. We interpret HB 2021's direction for us to "ensure" continual progress to give us the authority to require a utility to take actions outside the context of the regulatory determination whether to acknowledge a CEP (*i.e.*, to procure additional resources or make necessary infrastructure investments).[81] Such required

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[79] Order No. 22-390, Appendix A at 16.
[80] OAR 860-027-0400(11).
[81] As NWEC pointed out in Docket No. UM 2225, if a utility appears to be falling behind on progress to the targets, we should be in a position to "proactively provide additional requirements to a utility to help ensure that targets are actually met." Order No. 23-061 at 6.

actions would stand in contrast to a fundamental premise of the PUC's IRP acknowledgment decisions—that IRP decisions do not direct a utility to take or not take specific actions, except as it relates to analysis required in future plans or regulatory filings. Acknowledgment decisions inform the cost recovery risk the utility faces as it decides to take or not take certain resource actions, actions that it may choose to defer and evaluate again in the next IRP update or full IRP cycle.[82] If we conclude that utilities are not making "continual progress" or "taking actions as soon as practicable" such that we must direct additional utility actions, we may need to initiate separate proceedings because certain types of direction could require contested case adjudication subject to appellate review, rather than the more accessible proceedings we use for IRP/CEP acknowledgment review.

We also note that we must interpret section 4(6) in a manner that enables the orderly administration of our regulatory program, and thus we make explicit that we will not evaluate continual progress *continually*. In a context where nearly every action taken by a regulated utility could impact its progress toward HB 2021 targets, arguments about impacts on continual progress could be made in nearly every regulatory proceeding. Of most direct relevance are utility RFPs, which are generally designed to carry out the actions set forth in IRPs and CEPs but may include their own analysis to refine procurement targets. We do not intend, in Commission-overseen RFPs, to make additional, separate determinations of continual progress from those made in IRPs, CEPs, and their updates, nor to change how we characterize our RFP approval and short list acknowledgment decisions.

Planning is, by its nature, indicative and strategic, not determinative or certain, and HB 2021 places its continual progress requirements firmly within the planning context. IRP models are an idealized estimation of annual dispatch and the projected emissions in any future year greatly depend on estimated weather conditions, resource deployment by other utilities and many other factors outside the utilities' control. Moreover, RFPs historically have produced actual bids that diverge in many respects from the proxy resources modeled in IRPs. Contract negotiations and project implementation then lead to additional divergence from the idealized world of the IRP model. As observed in the annual power cost cases, actual dispatch and thus actual emissions are then impacted by emergent events such as natural gas constraints or hydroelectric production that the IRP can only estimate as one among many potential scenarios. As CEPs and IRPs are planning exercises, evaluating continual progress will similarly be directional, with the ability to look at actual performance in the next round of IRPs, CEPs, and updates and use that information to adjust forward direction and, ultimately, to inform rate case and compliance decisions.

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[82] Acknowledgment of CEPs may be seen, similarly, as referential to the future determination of compliance with the targets, with non-acknowledgment raising the risk of penalties and other consequences for non-compliance.

E. Phase II: HB 2021, Section 10 (Cost Cap)

In our scoping order, we posed three additional questions to seek input on whether additional guidance in a second phase of this proceeding would make other proceedings more efficient. Based on several responses to the Phase I(b) questions posed by the scoping order,[83] as well as questions arising in other dockets,[84] we determine that we will initiate Phase II of this proceeding to address threshold uncertainties surrounding HB 2021 section 10's cost cap for utilities (Issue I(b)(1)). Although many details of cost cap implementation are more appropriate for either a Staff-led process or a process initiated under section 10, we note several critical questions of statutory interpretation on which parties have asked for Commission direction.

We therefore direct the Commission's Administrative Hearings Division (AHD) to establish a procedural schedule for Phase II, beginning with a brief scoping process to refine the specific questions we will address related to section 10's cost cap. AHD should solicit input from the parties to refine or modify the following initial questions we have identified:

a. 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?

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[83] *See* NW Energy Coalition & Renewable Northwest Opening Brief at 15 (July 24, 2023); Portland General Electric and PacifiCorp d/b/a Pacific Power Joint Opening Brief at 15-17 (July 24, 2023); NewSun Energy LLC Opening Brief at 15-16 (July 24, 2023); Oregon Solar + Storage Industries Association Opening Brief at 10 (July 24, 2023); Oregon Citizen's Utility Board Opening Brief at 23 (July 25, 2023).

[84] *See In the Matter of Portland General Electric's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Alliance of Western Energy Consumers (AWEC) Response to Staff Comments at 5-6 (Nov. 21, 2023) *Id.*, Staff Report at 19 (Dec. 14, 2023); *In the Matter of PacifiCorp's dba Pacific Power's 2023 Integrated Resource Plan*, Docket No. LC 82, AWEC Round 1 Comments at 5-7 (Oct. 25, 2023); *Id.*, PacifiCorp Response to Round 1 Comments at 25-26 (Dec. 1, 2023).

b. 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 Section 10?[85]

c. 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?

d. 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)?

We will give careful consideration to refinements or modifications to these questions requested by the parties, but we do not intend to broaden these proceedings to supplant activities best undertaken in a Staff-led process, such as establishing practices for analyzing or reporting costs in IRPs, CEPs, and RFPs or processes for adjudicating petitions under section 10. We recognize that our answers to questions of statutory interpretation, may inform Staff-led implementation work, and therefore we seek to reach resolution to these questions in a time frame that serves to inform Staff's revisions to planning and procurement processes and rules, planned for 2024. We also invite feedback on the accessibility of the process and ask AHD to consider that feedback in its recommendations.

At this time, we do not intend to pursue any of the other Phase I(b) questions in future phases of these proceedings. We will consider questions surrounding Oregon-regulated REC-based programs, other REC-related issues, and early compliance incentives as they arise.

[85] *See In the Matter of PacifiCorp's dba Pacific Power's 2023 Integrated Resource Plan*, Docket No. LC 82, AWEC Round 1 Comments at 5-7 (Oct. 25, 2023); *see also Id.*, PacifiCorp Response to Round 1 Comments at 25-26 (Dec.1, 2023).

IV. ORDER

IT IS ORDERED that:

1. Future CEP rulemakings shall reflect the guidance contained in this order; and
2. The Commission's Administrative Hearings Division shall initiate Phase II of these proceedings consistent with the direction in this order.

Made, entered, and effective Jan 5, 2024.

Megan W. Decker
Chair

Letha Tawney
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.