IN THE CIRCUIT COURT OF THE STATE OF OREGON

FOR THE COUNTY OF MARION

NEWSUN ENERGY LLC, a Delaware limited liability company, Petitioner, v. OREGON PUBLIC UTILITY COMMISSION, an agency of the State of Oregon, Respondent.	Case No. 24CV29609 **PETITION FOR JUDICIAL REVIEW OR IN THE ALTERNATIVE TO COMPEL AGENCY ACTION PURSUANT TO ORS 183.484 AND 183.490** (Oregon Administrative Procedures Act, ORS 183.310-183.690) Statutory Fee: ORS 21.135(2)(a), (e)

Petitioner NewSun Energy LLC ("NewSun") petitions for judicial review of a final order in other than contested case pursuant to ORS 183.484, an order compelling agency action pursuant to ORS 183.490, declaratory relief, and alleges as follows:

OVERVIEW OF THE CASE

1.

This case arises out of the Oregon Public Utility Commission's (the "PUC" or the "Commission") Order No. 24-096 (the "Final Order"), issued on April 18, 2024 in *In the Matter of Portland General Electric Company, 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80 ("LC 80"). A copy of the PUC's Final Order is attached hereto as Exhibit A. In the Final Order, the PUC paradoxically acknowledges Portland General Electric Company's ("PGE") 2023 Integrated Resource Plan ("IRP") while simultaneously rejecting PGE's Clean Energy Plan ("CEP"). In other words, the PUC determined that PGE's resource procurement plan is simultaneously sufficient and deficient under applicable law. The Final Order is akin to a building inspector finding that a building has complied with all applicable code requirements and

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may proceed with construction while simultaneously denying an electrical permit due to faulty wiring. The conflicting conclusions set forth in the Final Order constitute a clear legal error, abuse of agency discretion, and are not supported by substantial evidence.

2.

Under Oregon law, regulated electric utilities like PGE must file "integrated resource plans," or IRPs, for review and acknowledgment by the Commission. *See* OAR 860-027-0400(3). The IRP process was developed primarily to prevent utilities from over-investing in generating resources at the expense of their ratepayers in order increase the financial returns realized by their shareholders. The IRP process also ensures that the utility has adequately planned to meet the changing electrical needs of its retail customers. Finally, the IRP must demonstrate that the utility's generating resources are being procured, operated, and maintained in compliance with applicable law to ensure their availability for retail load service.[1] For example, a hydroelectric generating facility that may be shut down because it is operating out of compliance with its FERC license presents a risk for ratepayers. Projecting the long-term availability of a legacy coal plant notwithstanding its violation of current or future air emissions regulations would be unreasonable and imprudent. Likewise, "planning" to construct a solar or wind generating facility in an isolated wheat field that is miles (or hundreds of miles) from the nearest high-voltage transmission facilities would also be unreasonable and imprudent.

3.

The Commission is charged with overseeing and either "acknowledging" or rejecting the utility's IRP. The Commission reviews each utility's IRP through a public docket that is subject to significant public comment and participation. *See* OAR 860-027-0400. In this case, PGE's IRP was reviewed by the Commission in a docket designated by the Commission as LC 80. The IRP review process is lengthy and very data intensive, analyzing thousands of pages of

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[1] *In re Pub. Util. Comm'n of Or. Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at Appendix A (Jan. 8, 2007) as corrected by Errata Order No. 07-047 (Feb. 9, 2007) ("The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.").

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comments and inputs including financial analyses, construction costs, performance of various asset types, supply contracts, fuel costs, customer growth patterns, and regulatory considerations. The Commission's IRP review process culminates with a formal, written decision issued by the Commission. The Commission's IRP decision is incredibly consequential in terms of establishing the trajectory of future utility resource acquisitions. If, for example, the Commission acknowledges a utility plan to acquire thousands of megawatts of power from a nuclear facility, then that would likely also have the effect of forgoing other types of resources such a wind and solar. Moreover, the final decision in the IRP proceeding is not reviewed, relitigated, or revised in any future Commission proceedings.

4.

The Court must also understand how the Utility resource plans and procurement decisions are driven by and respond to the utility's inherent profit motive. The costs recovered from retail ratepayers for generating resources owned by the utility are subject to a "return on equity," which is approximately ten percent (10%). This return on equity is profit for the utility's shareholders. The more equity that the utility invests in utility-owned resources, the more profits the shareholders realize. By contrast, the utility earns no profits for shareholders if it chooses to purchase the output of generating resources owned by competitive suppliers. Even where the output of competitive resources would be better for ratepayers—for example by being cheaper, cleaner, or having more reliable transmission—the utility is motivated to select its-own resource for the benefit of shareholders. Petitioner is not, of course, suggesting that profit-motives are inherently bad or unlawful, but merely providing context for the Commission's primary regulatory function of identifying and mitigating the utility's abuse of its monopoly power given the utility's unique position in which it could harm its ratepayers and the public both financially and physically.

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5.

The IRP acknowledgement process now also coincides with the timeline and process for emissions reductions and other requirements of HB 2021. *See* OAR 860-027-0400(4). In June 2021, the 81st Oregon Legislative Assembly passed House Bill 2021. By 2030, electric companies must ensure that their greenhouse gas emissions are ***80 percent*** below baseline levels. By 2040, electric companies must reduce their greenhouse gas emissions by ***100 percent*** below baseline. Complying with this new law will require a massive transformation of the electric generation capacity serving Oregon. Virtually all significant power procurement by Oregon's two affected regulated utilities, PacifiCorp and PGE, and in particular all development of new electric generation facilities, necessarily will be geared toward meeting electric utilities' obligations under HB 2021. All of this new clean-energy procurement must be planned-for through each utility's IRP processes.

6.

As part of the new planning process, ORS 469A.415 directs electric companies to develop "clean energy plans," or CEPs. The CEP must incorporate emissions goals and demonstrate that an electric company is making continual progress towards meeting those goals. ORS 469A.415(4). ORS 469A.420(2) directs the Commission to acknowledge a CEP if it is in the public interest, considering any reduction in greenhouse gas emissions, the economic and technical feasibility of the plan, costs and risks to customers, and any other relevant factors determined by the Commission. The Commission has adopted rules specifying it would review CEPs in the same docket, with the same parties, and subject to the same record as the IRP review process. *See* OAR 860-027-0400. As the Commission explained in the Final Order, "Oregon electric companies subject to HB 2021's requirements must submit a CEP to the Commission concurrent with the development of each IRP. CEPs must be based on or included in an [IRP] filing, and must be filed concurrently with the IRP." Order No. 24-096, p 4 (Internal citations

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omitted). Hence, by the Commission's own design, review of the utility's IRP and CEP is now inextricably intertwined in a single regulatory process.

7.

In addition to its duty to acknowledge CEPs within the IRP process, ORS 469A.415(6) directs the Commission to ensure that electric companies are taking a ***holistic*** approach to rapidly reducing greenhouse gas emissions. ORS 469A.415(6) reads:

> "The commission shall ensure that an electric company demonstrates continual progress as described in subsection (4)(e) of this section and is taking actions as soon as practicable that facilitate rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers."

ORS 4649A.415(6) requires the Commission to accomplish two additional goals regarding its oversight of electric companies. It must ensure that an electric company 1) "demonstrates continual progress [within the planning period towards meeting its clean energy targets]" and 2) "is taking actions ***as soon as practicable*** that facilitate ***rapid reduction*** of greenhouse gas emissions at reasonable costs to retail electricity consumers." (emphasis added).

8.

Embedded in the Commission's obligation to ensure that electric companies are taking actions "as soon as practicable that facilitate rapid reduction of greenhouse gas emissions" is the requirement of ORS 469A.405 that such zero-emission generation is generated "in a manner that provides direct benefits to communities ***in this state*** . . . ." (emphasis added). Section 2, paragraph 2 of HB 2021, codified at ORS 469A.405(2) requires "[t]hat 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[.]" The phrase "to the maximum extent practicable" could mean that *as much as 100%* of the new generation capacity needed should be sited in Oregon in order to benefit state, county, and community economic opportunities that

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could result in billions of dollars of investment and hundreds of millions of dollars in county and state tax revenue over the next two decades,[2] in addition to the creation of local jobs targeted by this Policy. The location of generating resources can also have a direct impact on public health and safety by increasing grid reliability and decreasing the wildfire risk posed by high voltage transmission lines.

9.

In the LC 80 docket at issue here, the Commission issued the Final Order in which it rejected PGE's CEP because PGE failed to show that it is taking action (*i.e.*, acquiring renewable resources) fast enough to meet its obligations under HB 2021. In the Final Order, the Commission wrote:

> "In declining to acknowledge PGE's CEP, we base our decision on the statutory requirement that we must determine that the plan is consistent with HB 2021's targets. Staff made a persuasive case, supported by nearly every other stakeholder in this process, that PGE's unwillingness to incorporate further analysis and update the preferred portfolio when material concerns were identified about whether it was sufficient to meet the compliance requirements left us with insufficient insight to determine the plan's consistency with HB 2021's targets.

Order 24-096, p. 17. Nevertheless, the same Final Order acknowledges PGE's IRP. The bottom line is that the utility's plan to acquire clean generating resources under the IRP cannot be legally sufficient if the utility's plan to acquire clean generating resources under the CEP is legally deficient. Otherwise, the IRP is little more than a plan to violate HB 2021.

10.

The Final Order is invalid because it acknowledges a resource plan that—by the Commission's own admission—fails to meet the emission reductions obligations set forth in HB 2021. The Commission cannot lawfully approve an IRP that is out of compliance with HB 2021.

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[2] A few *small* projects in Harney and Lake County, some of which were developed by NewSun affiliates, already pay over $1MM per year in property taxes to these two counties. Similarly, in Crook County, hundreds of thousands per year of property taxes are paid by just over 100 MW of recently developed solar projects. For context, many thousands of MW of solar and wind will be required to reach 100% emissions reductions, comprising potentially tens of millions *per year* of Oregon country property taxes at risk relative to proper implementation of this policy. Wind projects in Morrow, Sherman, and Gilliam Counties also already pay millions in revenue to those counties.

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The Commission recognized in the Final Order that its conflicting decisions on the IRP and CEP are "confusing." "We disagree with New Sun's assertion that the IRP and CEP are too tightly linked to acknowledge one and not the other. It is perhaps also a confusing outcome to those less intensively engaged in our processes. Our conclusion is that the IRP near-term actions set PGE on a path to compliance." Order 24-096, p. 18. In other words, the Final Order simultaneously concludes that there is "insufficient insight to determine the plan's consistency with HB 2021's targets," and that PGE's plan puts it "on a path to compliance." These statements cannot both be true. The Final Order is not just "confusing," it is irreconcilable.

11.

Aside from documenting PGE's failure to demonstrate compliance with emissions reductions requirements, the Final Order also fails to address PGE's compliance with the other policy goals and legal requirements of HB 2021. For example, the Final Order does not adequately explain how PGE's resource plan will—"to the maximum extent practicable"—provide additional direct benefits to communities in the state or Oregon in the form of creating and sustaining meaningful living wage jobs, promote workforce equity, and increase energy security and resiliency. *See* ORS 469A.405(2).

12.

The Final Order also lacks substantial evidence in the record to show that PGE's resource procurement plan complies with applicable laws other than HB 2021. The IRP lacks transparent and intelligible modeling showing that PGE's preferred resource procurement plan would comply with other applicable environmental regulations such as Clean Air Act and the Environmental Protection Agency's Greenhouse Gas Standards. The Final Order is deficient in failing to adequately address IRP compliance with applicable law.

13.

The Final Order is also not supported by substantial evidence in the record to the extent that PGE's resource plan relies on the existence or construction of phantom transmission assets

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that would be needed to reach PGE-owned, PGE-preferred, or other non-viable generating resources. PGE's "plan" appears to assume the existence or the future construction of new high-voltage transmission lines needed to move the output of preferred generating resources to load. At best, construction of such new transmission lines will not occur before 2030, or even 5 or 10 years thereafter. And it may never happen at all. The Commission noted that "[t]he results of PGE's analysis highlight that transmission is ***the largest factor*** influencing resource additional, costs, and risks." Order No. 24-096, p. 7 (Emphasis added). The Commission noted that, "[i]n its first and second round of comments, Staff voiced concerns regarding PGE's transmission action plans, arguing that the transmission actions in the action plan were vague and required additional analysis." *Id.* at p. 9. Further, "Staff pointed out that PGE's preferred portfolio provided no analysis regarding how the Bethel to Round Butte upgrade would enable integration of renewable resources." *Id.* Thus, the Final Order approves a resource plan notwithstanding the fact that "the largest factor" in such resource plan is "vague" and, in certain critical respects, "provided no analysis."

14.

The Final Order is also not supported by substantial evidence in that it does not sufficiently analyze the existence and use of competitive power supply options. For example, the Final Order omits any discussion of utility-scale and large-scale rooftop solar resource development in the Willamette Valley. While PGE's preferred portfolio includes a token amount of Community Based Renewable Energy ("CBRE") resources, the use of such CBRE resources is artificially capped. There was extensive testimony in the record about alternative generating resource options on or near PGE's electric system that could be developed without delay and that would not require the construction of major new transmission lines and that should be considered by PGE in its resource planning. The Final Order ignores this testimony and allows PGE to select resources that may more dangerous, more speculative, less reliable, and more expensive.

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15.

Finally, the Final Order is deficient in that it fails to address whether PGE's resource plan adequately mitigates ratepayer risk. Are PGE's projected needs for capacity and energy sufficient to ensure system reliability in the face of future spikes in demand—such as the one caused by the June 2021 heat dome event? Or will PGE's ratepayers be subject to risks of blackouts and/or wholesale energy market price spikes? Further, even if PGE's transmission plans were realistic—which they are not—does a resource plan that relies heavily on the construction of miles and miles of new high-voltage transmission lines expose PGE's ratepayers and other Oregonians to an increased risk of wildfire? Even if these transmission lines can eventually be constructed, the 10-15 year planning, permitting and development horizon would leave ratepayers exposed to market and reliability risks far longer than is prudent or reasonable. Another regulated utility (PacifiCorp) was recently found to be grossly negligent with respect to the operation and maintenance of its high voltage transmission lines, which gross negligence resulted in the deaths of nine people and hundreds of millions of dollars in property damage. In their resource plans, utilities should be seeking to mitigate such transmission risks not expand them. A proper vetting of PGE's preferred resource plan should consider and balance such risks. The Final Order does not.

16.

This is a serious and urgent matter for the State of Oregon. Decisions are now being made that will determine the location and siting of billions of dollars of new electricity generating infrastructure procurement and hundreds of millions of dollars of corresponding tax revenue. PGE is hungry to earn a return on equity on as much of this new resource investment as possible, regardless of consequences to public health and safety and whether PGE has met its obligations under HB 2021 to rapidly reduce its greenhouse gas emissions. This includes decisions about whether the construction, operation, and management of such infrastructure will directly benefit communities in Oregon as required by HB 2021. The deadline for PGE and

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Oregon's other regulated utilities to meet their first emissions goal is looming. Now is the time to address these issues, so that—as new infrastructure is developed—Oregonians may reap the benefit of the policies adopted by the Legislature.

THE PARTIES

17.

Petitioner NewSun Energy, LLC is a Delaware limited liability company that invests in and has and manages affiliates engaged in the development of renewable energy and non-emitting generation and capacity facilities, including small power production qualifying facilities and related activities, in Oregon and throughout the Pacific Northwest. New Sun's principal place of business is in Bend, Oregon.

18.

Respondent Oregon Public Utility Commission is an administrative agency of the State of Oregon, with the power and jurisdiction to supervise and regulate public utilities and telecommunications utilities in this state, and with regulatory authority over the resource procurement of retail electricity providers.

STANDING, JURISDICTION, AND VENUE

19.

NewSun has standing pursuant to ORS 183.480(1). That statute provides that "any person adversely affected or aggrieved by an order or any party to an agency proceeding is entitled to judicial review of a final order, whether such order is affirmative or negative in form." ORS 183.480(1). Under ORS 183.310(7), a "party" includes "[e]ach person or agency named by the agency to be a party" and "[a]ny person requesting to participate before the agency as a party or in a limited party status which the agency determines either has an interest in the outcome of the agency's proceeding or represents a public interest in such result." Under ORS 183.310(8), "'[p]erson' means any individual, partnership, corporation, association, governmental subdivision or public or private organization of any character other than an agency."

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20.

NewSun has standing as a party to the agency proceeding at issue because it is an intervenor in LC 80.

21.

NewSun also is a person adversely affected or aggrieved by the Final Order. As a company whose business activities provide direct benefits to communities in Oregon in the forms of creating and sustaining meaningful living wage jobs, promoting workforce equity, and increasing energy security and resiliency, NewSun's activities further the interests that the legislature expressly wished to have considered in the implementation of HB 2021.

22.

The Court has jurisdiction pursuant to ORS 183.484.

23.

Petitioner's petition for review is timely. ORS 183.484(2) provides:

> "Petitions for review shall be filed within 60 days only following the date the order is served, or if a petition for reconsideration or rehearing has been filed, then within 60 days only following the date the order denying such petition is served. If the agency does not otherwise act, a petition for rehearing or reconsideration shall be deemed denied the 60th day following the date the petition was filed, and in such case petition for judicial review shall be filed within 60 days only following such date. Date of service shall be the date on which the agency delivered or mailed its order in accordance with ORS 183.470."

24.

The Final Order was issue on or about April 18, 2024. Petitioner's petition for review, appealing from the Final Order, was filed within 60 days.

25.

Venue is proper in Marion County under ORS 183.484(1), which provides "[p]roceedings for review under this section shall be instituted by filing a petition in the Circuit Court for Marion County or the circuit court for the county in which the petitioner resides or has a principal business office."

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26.

The PUC's April 18, 2024 order is a final order in other than contested case because it constitutes agency action in writing not arising from any of the four categories described in ORS 183.310(2)(a). This Court is the arbiter of whether an order is "Final" for the purposes of judicial review. This Court will note that the Commission also issued Order 24-097, one that the Commission clearly identified as a Final Order, in the same docket and on the same day as Order 24-096. The Commission does not have the authority to unilaterally dictate that one of these Final Orders is subject to judicial review while the other is not.

FIRST CLAIM FOR RELIEF

(ORS 183.484—Judicial Review of an Order in Other Than a Contested Case)

27.

Petitioner realleges and incorporates by reference paragraphs 1-26 as if fully stated herein.

28.

ORS 469A.415 explicitly directs the Commission to assess an electric utility's Clean Energy Plan for compliance with the greenhouse gas emissions reduction goals set forth in HB 2021.

29.

The Commission's Final Order rejected (did not acknowledge) PGE's CEP while simultaneously acknowledging PGE's 2023 IRP. The Commission's rejection of PGE's CEP compels the conclusion that PGE's IRP does not meet the goals of HB 2021. The Final Order is therefore outside the range of discretion delegated to the PUC.

30.

Accordingly, Petitioner is entitled to an Order from the Court remanding the Final Order to the PUC with instructions to issue a final order that is consistent with the Commission's conclusion that PGE's CEP was not acknowledged.

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SECOND CLAIM FOR RELIEF

(ORS 183.490 – Compel Agency Action)

31.

Petitioner realleges and incorporates by reference paragraphs 1-30 as if fully stated herein.

32.

ORS 469A.415(6) explicitly directs the Commission to "ensure that an electric company . . . is taking actions as soon as practicable that facilitate rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers."

33.

A utility's IRP sets in motion several years of resource planning; it is a critical tool of the Commission that enables it to ensure that its regulated utilities provide reliable and least-cost, least-risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing and planning for uncertainties.

34.

As such, PGE's IRP is the natural venue to ensure its HB 2021 obligations are on track to be met, and the Commission's failure to exercise such oversight amounts to a dereliction of its explicit obligations under ORS 469A.415(6).

35.

Accordingly, Petitioner asks the Court to compel the Commission to act as required by ORS 469A.415(6).

THIRD CLAIM FOR RELIEF

(DECLARATORY JUDGMENT)

36.

Petitioner realleges and incorporates by reference paragraphs 1-35 as if fully stated herein.

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37.

This Court has jurisdiction under Oregon's Declaratory Judgments Act, ORS 28.010–160.

38.

A present and actual controversy exists between the parties because the parties disagree as to whether HB 2021 requires the Commission to consider the statute's goals and purpose in its IRP acknowledgment orders.

39.

By failing to implement the requirements of HB 2021 within this IRP, the Commission is proceeding without probable cause. ORS 183.480(3).

40.

Petitioner will suffer substantial and irreparable harm if relief is not granted. ORS 183.480(3).

41.

Petitioner seeks a declaration from the Court that:

"ORS 469A.415(6) requires the Commission to exercise oversight of utility emissions reduction efforts within the IRP process."

PRAYER FOR RELIEF

WHEREFORE, Petitioner prays for relief as follows:

1. A declaration from the Court providing that Oregon Public Utility Commission is obligated to administer and enforce the provisions of ORS 469A.415(6).

2. An Order from the Court remanding the Final Order to the PUC with instructions to issue a final order that is consistent with the Commission's conclusion that PGE's CEP was not acknowledged.

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3. An Order from the Court compelling the Commission to act as expressly required by ORS 469A.415(6).

DATED: June 17, 2024.

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ORDER NO. 24-096

ENTERED Apr 18, 2024

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 80

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan.	ORDER

DISPOSITION: 2023 INTEGRATED RESOURCE PLAN ACKNOWLEDGED SUBJECT TO CONDITIONS; 2023 CLEAN ENERGY PLAN NOT ACKNOWLEDGED; RESUBMISSION OF CERTAIN PLAN ELEMENTS REQUIRED

I. SUMMARY

This order memorializes our decision made and effective at our January 25, 2024, Special Public Meeting, concerning Portland General Electric Company's 2023 Integrated Resource Plan (IRP) and Clean Energy Plan (CEP). We acknowledge PGE's 2023 IRP subject to the conditions in the attached December 14, 2023, Staff Report, and as discussed at the January 25 meeting and detailed in this order. We do not acknowledge PGE's CEP for the reasons summarized below. We direct PGE to revise and resubmit certain elements of the CEP with its next IRP/CEP update. We further direct the company to take additional actions as listed in Staff Report Attachments 1 and 2, and as modified and supplemented by our January 25 meeting discussion. Our determination and discussion of continual progress is presented in Order No. 24-097.

II. INTRODUCTION

Our review of PGE's 2023 IRP/CEP involved complex conversations about PGE's planning approach and resource strategy during a time of dynamic change in Western energy markets and Oregon state policy, particularly with the implementation of House Bill (HB) 2021. PGE's efforts represent the very first CEP filed in Oregon following the passage of HB 2021, and we commend PGE for the many ways in which its IRP/CEP set a solid foundation for advancing toward the ambitious goals the legislature set in

HB 2021. As promising as PGE's filing and the subsequent dialogue among PGE, Staff, and stakeholders in our IRP/CEP review process were in many respects, they also served to underscore the challenging work that will be required for successful implementation of HB 2021. We appreciate PGE's open engagement and willingness to adjust and receive feedback in many areas during the process; although we ultimately declined to acknowledge PGE's CEP, our acknowledgment of PGE's IRP with conditions reflects general alignment on near-term steps forward in PGE's resource strategy.

III. IRP PROCESS

A. Purpose

The objective of the IRP process is to ensure an adequate and reliable supply of energy at the least cost and least risk to the utility and its customers in a manner consistent with the public interest.[1] The expectations set in our IRP guidelines, as well as the broad stakeholder input they require the company and the Commission to seek, are meant to ensure a detailed and wide-ranging review of resource options, technology advancements, pricing scenarios, and risk profiles, all with the goal of testing the utility's conclusions.

The IRP process is intended to be iterative. Where weakness in the analysis or other issues are identified that are not material to the near-term action plan, Staff and stakeholders can help identify alternatives and improvements to be pursued in the next IRP, some of which may be directed in our acknowledgment order. We have conditioned our acknowledgment of IRPs when resolution of those issues or weaknesses is more significant to improving our confidence that near- or medium-term actions are well-justified. Particularly during a time of electric utility industry transition, IRPs should evaluate opportunities and strategies for course corrections as industry evolution comes into greater focus.[2] Although conditions may change before utility resource decisions are made, and the utility retains the responsibility to adjust its decision-making based on those conditions as appropriate, an acknowledged IRP remains an important reference document for use in subsequent Commission proceedings, including for cost recovery.[3]

B. Timing And Content

We require regulated energy utilities to prepare and file IRPs within two years of acknowledgment of the utility's last plan.[4] Our IRP guidelines provide procedural and

[1] *In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 2 (Apr. 20, 1989).
[2] *In the Matter of Portland General Electric Company, 2016 Integrated Resource Plan*, Docket No. LC 66, Order No. 17-386 at 2 (Oct. 9, 2017).
[3] Order No. 17-386 at 7.
[4] OAR 860-027-0400(3).

substantive requirements for utilities to meet in developing their IRPs.[5] Consistent with our guidelines, which require modeling of at least a 20-year time horizon, a utility's IRP must include the following key components:

- Identification of capacity and energy needs to bridge the gap between expected loads and resources;
- Identification and estimated costs of all supply-side and demand-side resource options;
- Construction of a representative set of resource portfolios;
- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;
- Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; and
- Creation of a two- to four-year action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.

In reviewing an IRP, we assess reasonableness based on the information available at the time. Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our examination of whether the costs associated with a utility's resource investment should be recovered in customer rates.[6] The question of whether a specific utility investment or procurement decision was prudent and reasonable will be examined in the subsequent rate proceeding.

IV. CEP PROCESS

A. Purpose

The PUC is tasked with ensuring progress towards, and evaluating compliance with, the emissions reductions targets required by HB 2021. Oregon electric companies subject to HB 2021 must file CEPs, which we are charged with evaluating for acknowledgment pursuant to ORS 469A.415.[7] CEPs must meet statutory requirements set forth in ORS 469A.415(4), and also must demonstrate continual progress towards meeting the HB 2021 targets in a way that results in "an affordable, reliable and clean electric system."[8]

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[5] *See In the Matter of Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 (Jan. 8, 2007) and Order No. 07-047 (Feb. 9, 2007) (adopting 13 IRP Guidelines); *In the Matter of Investigation into the Treatment of CO_2 Risk in the Integrated Resource Planning Process*, Docket No. UM 1302, Order No. 08-339 (June 30, 2008) (refining Guideline 8 addressing environmental costs).
[6] IRP background is taken from Docket LC 77, Order No. 22-178 at 3-4 (May 23, 2022).
[7] ORS 469A.410(1) lists the required greenhouse gas emission reductions; the Commission's required evaluation is described in ORS 469A.415(4)(e) and (6).
[8] ORS 469A.415(4)(f).

B. Timing and Content

Oregon electric companies subject to HB 2021's requirements must submit a CEP to the Commission concurrent with the development of each IRP.[9] CEPs "must be based on or included in an [IRP] filing," and must be filed concurrently with the IRP.[10] ORS 469A.415(4) requires that each CEP must:

> (a) Incorporate the clean energy targets set forth in ORS 469A.410;
> (b) Include annual goals set by the electric company for actions that make progress towards meeting the clean energy targets * * * including acquisition of nonemitting generation resources, energy efficiency measures and acquisition and use of demand response resources;
> (c) Include a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards * * *;
> (d) Examine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy;
> (e) Demonstrate 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; and
> (f) Result in an affordable, reliable and clean electric system.[11]

The actions and investments proposed in a CEP can include "the development or acquisition of clean energy resources, acquisition of energy efficiency and demand response * * * development of new transmission * * * retirement of existing generating facilities, changes in system operation and any other necessary action."[12]

We have adopted rules to guide initial CEP filings, which state that the CEP must "present annual goals for actions that balance expected costs and associated risks and uncertainties for the utility and its customers, including a demonstration of making continual progress towards meeting the clean energy targets, the pace of greenhouse gas emissions reductions, and community impacts and benefits."[13] The CEP must be "written in language that is as clear and simple as possible, with the goal that it may be understood by non-expert members of the public."[14]

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[9] ORS 469A.415(1).
[10] ORS 469A.415(3). If filing the CEP concurrently with the IRP would create an undue burden or a significant issue, the electric company may file a written request with the Commission to extend the filing date by up to 180 days after the IRP was filed.[10]
[11] ORS 469A.415(4)(a) - (f); statutory references omitted.
[12] ORS 469A.415(5).
[13] OAR 860-027-0400(5).
[14] *Id.*

C. Acknowledgment

As we stated in our recent order in docket UM 2273, CEP acknowledgment is similar to IRP acknowledgment in that it "do[es] not direct a utility to take or not take specific actions, except as it relates to analysis required in future plans or regulatory filings."[15] Just as IRP acknowledgment decisions "inform the cost recovery risk the utility faces as it decides to take or not take certain resource actions," we stated that CEP acknowledgment decisions "may be seen * * * as referential to the future determination of compliance with the [clean energy] targets, with non-acknowledgment raising the risk of penalties and other consequences for non-compliance."[16]

The law requires us to acknowledge utility-filed CEPs if they are consistent with the clean energy targets and in the public interest.[17] In determining whether a CEP is in the public interest, the Commission is to consider: (1) anticipated greenhouse gas emissions reductions 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) the availability of federal incentives; (5) costs and risks to customers; and (6) other relevant factors.[18]

V. PGE'S 2023 IRP AND CEP

PGE concurrently filed its IRP/CEP on March 31, 2023. A procedural schedule was established, and the plans were reviewed together in this docket. Stakeholders provided three rounds of written comments prior to Staff filing its final recommendations on December 14, 2023. PGE and stakeholders filed responses to Staff's report on January 12, 2024. We held two special public meetings that provided the opportunity to extensively discuss the plans with Staff, stakeholders, and the company (January 18, 2024) and to deliberate and reach our acknowledgment determinations (January 25, 2024).

PGE estimates significant growth in both its energy and capacity needs over the next two decades, driven by both high load growth projections and the transition from fossil fuel to clean energy resources. HB 2021 requires PGE to reduce emissions to 80 percent below baseline level by 2030. PGE's plans prioritize procurement of existing, commercially-proven renewable energy technologies to ensure that it has appropriate non-emitting resources in place to meet the 2030 emissions reduction goals. PGE's IRP/CEP includes annual goals for actions that make progress towards meeting the clean

[15] *In the Matter of Public Utility Commission of Oregon, Investigation into House Bill 2021 Implementation Issues*, Order No. 24-002 at 30 (Jan. 5, 2024); OAR 860-027-0400(9)-(10).
[16] *Id.* at 30, n 82.
[17] ORS 469A.420(2).
[18] ORS 469A.420(2)(a)-(f).

energy targets, a demonstration of anticipated emissions reductions through 2040, resource portfolio cost and risk analyses, incorporation of customer actions, consideration of community benefits and impacts, addressing transmission constraints, as well as accounting for federal incentives and evaluating the effect of its resource plan on system reliability.

A. Projected Resource Need and Action Plan

PGE projects a need for 1,254 MWa of energy, as well as capacity additions of 1,538 MW for summer net peak load and 1,284 MW for winter peak load through 2028. To meet these energy and capacity needs, and to position itself to meet HB 2021 emissions reduction targets by 2030, PGE details five action plan items: customer resource actions (i.e., procurement of energy efficiency and demand response), community based renewable energy (CBRE) procurement, energy procurement, capacity procurement, and securing additional transmission. PGE characterizes its near-term action plan as "low regrets" or the best available to meet needs and reduce emissions, given its current transmission constraints, uncertainties related to future load, cost and availability of emerging technology and potential regional market developments.

By 2026, PGE plans to acquire 66 MW from CBRE resources. By 2028, PGE plans to acquire 1,254 MWa (251 MWa energy per year for five years), 905 MW of summer capacity, and 787 MW of winter capacity. Additionally, by 2028, PGE plans to acquire 182 MWa of cost-effective customer-based energy efficiency, as well as 211 MW summer capacity and 158 MW winter capacity through customer demand response. PGE also plans to pursue and explore transmission upgrade options to accommodate the anticipated load growth on its system and integrate necessary resources to serve that load. In response to Staff comments, PGE clarified in its round 2 comments that it plans to develop a comprehensive transmission study which would explore options to alleviate congestion on the South of Allston flowgate and upgrade the Bethel-Round Butte line.

B. Preferred Portfolio

The preferred portfolio represents PGE's proposed resource mix for meeting projected customer demand over the long-term planning horizon and achieving the emissions reduction targets. PGE developed its preferred portfolio by first designing 39 resource portfolios and analyzing each across a range of future scenarios using the capacity expansion model ROSE-E.[19] PGE's preferred portfolio follows a linear glidepath to the HB 2021 emissions targets, adds 100 percent of the projected CBRE potential (as

[19] ROSE-E was developed prior to PGE's 2019 IRP and used to conduct portfolio analysis in those proceedings. PGE provides more detail about the model in its initial filing at 529, Appendix H (Mar. 31, 2023).

determined in a separate study), and emphasizes the importance of evaluating transmission needs for the first time in a PGE IRP.

The results of PGE's analysis highlight that transmission is the largest factor influencing resource additions, costs, and risks. Although PGE posits that emerging non-greenhouse gas (GHG)-emitting technologies—like nuclear, hydrogen, and storage—could mitigate dependence on transmission, PGE stresses that transmission upgrades are necessary to deliver resources needed to meet the 2030 HB 2021 targets and serve growing load. PGE's preferred portfolio contains a mix of resources including wind, battery storage, hybrid generation and storage facilities, CBREs and transmission expansion.

PGE's customer actions, which originally called for scaling back energy efficiency acquisition to avoid near-term rate impacts, shifted in response to Staff's comments highlighting that modeling results strongly favored near-term energy efficiency. PGE revised its action to incorporate the 53 MWa of additional energy efficiency that the model had selected by 2030.[20]

VI. POSITIONS PRESENTED

We appreciate the participation and effort made by stakeholders and PGE in this case through written comments, thoughtful and persistent engagement in Commissioner workshops in September 2023, and during our January 18, 2024, Special Public Meeting. Over the course of this review, several areas of agreement were reached and reflected in Staff's final memo. The planning accomplished by PGE in this dynamic environment was valuable and made more so through the work of Staff and stakeholders.

A. Staff

1. Overall Approach

At the beginning of the review process, Staff stated it would rely on established planning principles, take direction from HB 2021 requirements, and consider PGE's efforts to incorporate priorities from docket UM 2225.[21] Staff further noted that it would also "work to identify opportunities to improve upon the initial CEP guidance and evolve the Commission's longstanding planning and resource acquisition policies."[22] Staff provided

[20] PGE Round 2 Comments at 36-37 (Nov. 21, 2023).
[21] See, *HB 2021 Investigation into Clean Energy Plans, Docket no. UM 2225.* Staff outlined the HB 2021 requirements from 469A.420 as: "(a) Any reduction of greenhouse gas emissions that is expected through the plan, and any related environmental or health benefits; (b) The economic and technical feasibility of the plan; (c) The effect of the plan on the reliability and resiliency of the electric system; (d) Availability of federal incentives; (e) Costs and risks to the customers; and (f) Any other relevant factors as determined by the commission." Staff Initial Comments at 2 (May 4, 2024).
[22] *Id.*

an initial set of observations on PGE's resource strategy and identified opportunities for improvement.

On October 24, 2023, Staff provided its second round of comments and draft recommendations. These included recommending that PGE revise its action plan to acquire all cost-effective energy efficiency; the Commission not acknowledge PGE's avoided cost inputs because of issues with qualifying facility assumptions; PGE file a transmission study thoroughly evaluating options to relieve congestion at the South of Allston and Cross Cascades South flow gates; and the Commission not acknowledge the long-term resource strategy unless PGE made revisions to its GHG emissions modeling. Staff submitted final recommendations on December 14, 2023.

2. Energy Efficiency

Staff stated that PGE's quantity of energy efficiency in its preferred portfolio was based on avoided costs that were "out of date" and which did not reflect a forecast consistent with the HB 2021 compliance requirements.[23] Staff noted that PGE's initial evaluation demonstrated benefits associated with an additional 50 MWa of energy efficiency, beyond the energy efficiency previously identified by the Energy Trust of Oregon (ETO) and provided to PGE as an input to the IRP modeling. The modeling illustrated that this additional energy efficiency was cost-effective, lowered long-term cost and risk, and provided portfolio benefits not currently identified by the energy efficiency cost-effectiveness analysis using avoided costs established prior to implementation of HB 2021.[24] In opening comments, Staff recommended that PGE include the additional 50 MWa of energy efficiency in its preferred portfolio, noting that the acquisition would reduce long-term costs by $476 million, represent a smaller quantifiable risk than any other resources contained in PGE's preferred portfolio, and would have several near-term benefits for all customer classes, including lowering energy bills and enhancing building resilience.

In final comments, Staff maintained its recommendations that PGE pursue all cost-effective energy efficiency, including an additional 53 MWa identified in PGE's revised IRP/CEP, and that PGE engage with Staff, stakeholders and the ETO regarding implementation.[25] PGE included Staff's energy efficiency recommendations in its final action plan.

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[23] Staff Opening Comments at 27 (July 28, 2023).
[24] Staff Initial Comments at 3-4 (citing *PGE2023 IRP/CEP, Section 11.4.4* at 275 (May 4, 2023).).
[25] Staff Round 2 Comments and Recommendations at 7-9 (Oct. 24, 2023).

3. *Transmission*

In its first and second round of comments, Staff voiced concerns regarding PGE's transmission action plans, arguing that the transmission actions in the action plan were vague and required additional analysis. For instance, Staff noted that PGE's plan included an upgrade to the South of Allston transmission line, which the company stated would add 400 MW of capacity by 2030. PGE noted that this additional capacity and timeline were dependent on immediate transmission construction. Staff noted that it "hoped to see a more rigorous analysis" of this item, given PGE's urgency and coupled with the fact that transmission is a long lead-time resource.[26] Staff pointed out that PGE's preferred portfolio provided no analysis regarding how the Bethel to Round Butte upgrade would enable integration of renewable resources. After reviewing Staff's initial recommendations, PGE agreed to conduct a transmission study prior to the next IRP update.

4. *GHG Emissions Modeling*

Throughout the review process, Staff voiced concerns regarding PGE's GHG emissions modeling approach. Staff noted that PGE did not analyze the emissions likely required to serve native load on an hourly basis but relied on annual totals to determine compliance.[27] This annual approach did not bear enough fidelity to the final compliance requirements to ensure PGE could meet the HB 2021 targets with the preferred portfolio. Staff found the approach likely over estimated access to zero carbon energy in times of high customer load needs for PGE and other utilities in the region. In addition, Staff expressed concern that PGE's annual approach over-estimated sales of natural gas generated energy to other entities when that energy would instead be needed to meet native load. The approach also assumed an unrealistic opportunity for PGE to count renewable energy that might be sold during times of high generation as instead being utilized by load.[28] In response to Staff's concerns, PGE roughly estimated emissions on an hourly basis and Staff found the result concerning, noting that ultimate compliance required significant access to non-emitting energy from the market.[29] Staff concluded that the preferred portfolio may fall short of compliance and that additional clean resources may be necessary.

5. *December 14, 2023 Staff Report and Recommendations*

The attached December 14, 2023 Staff Report contains final recommendations for Commission consideration and a detailed list of expectations that Staff intends to pursue

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[26] Staff Round 2 Comments and Recommendations at 14-15 (Oct. 24, 2023).
[27] Staff Opening Comments at 6-7 (July 7, 2023).
[28] Staff Opening Comments at 8 (July 7, 2023).
[29] Staff Final Memo at 16.

in engaging on PGE's future IRPs and CEPs.[30] Overall, Staff recommends that we acknowledge PGE's 2023 IRP and action plan items with conditions.[31] Staff recommends that we decline to acknowledge PGE's CEP and require PGE to revise and resubmit its CEP with the company's 2025 IRP/CEP update after performing the enhanced modeling of GHGs described below and update its preferred portfolio accordingly.[32]

Staff's recommendations are summarized below:

Staff Recommendation 1. Acknowledge PGE's CBRE action item subject to the condition that PGE pursue the broader range of procurement actions that it identified in comments in this docket.

Staff Recommendation 2. Acknowledge PGE's Energy and Capacity action items subject to the following condition: Before issuing its next utility-scale request for proposals (RFP), PGE will file a proposal for a Long Lead-Time Resource request for information (RFI) developed via a stakeholder process in LC 80 and facilitate a stakeholder discussion (workshop) on the findings of the RFI and allow sufficient time for stakeholder review of its RFI before proposing its next steps.

Staff Recommendation 3. Decline to acknowledge PGE's expected reduction of GHG emissions in the CEP as credible based on the preferred portfolio and direct the company to make the following revisions and resubmit the revised plan before its IRP/CEP Update in 2025: PGE shall conduct hourly production cost simulation of its preferred portfolio under the reference case in a manner that separately tracks hourly purchases and hourly sales. PGE will use this analysis to revise its GHG emissions forecast and to revise its submission to the Oregon Department of Environmental Quality (DEQ); PGE shall update the preferred portfolio accordingly and provide a brief narrative explanation of the key planning insights derived from this exercise.

Staff Recommendation 4. Direct PGE to work with Staff to propose a new method for calculating avoided costs in docket UM 1893, *Investigation into the Methodology and Process for Developing Avoided Costs Used in Energy Efficiency Cost-Effectiveness Tests*. The avoided cost proposal should resolve the shortcomings identified by PGE and Staff, including but not limited to the shift from one avoided capacity value to annual

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[30] Staff invites us to take action on its *recommendations*, which represent either recommended conditions to our acknowledgment of the IRP or requirements for future IRPs and CEPs that Staff recommends be set forth in our order. In contrast, Staff sets forth its *expectations* only for transparency and to ensure general Commission alignment, explaining that it intends to pursue its expectations for future IRPs and CEPs in collaboration with the company and other stakeholders during the development of the next plans but does not recommend that we establish them as requirements in our order.
[31] Staff Report, Attachment 1, Recommendations 1 and 2 at 26 (Dec. 14, 2023).
[32] *Id.*, Recommendation 3.

values, the impact of constraints observed in the model, and the need to procure clean electricity not captured by forward market prices.

Staff Recommendation 5. Direct PGE in the next IRP/CEP Update to include a small-scale renewable energy resource (SSR) compliance assessment. The SSR analysis should state the projected SSR compliance position, broken out by relevant resource types, and outline the actions the company plans to take to fill any identified SSR shortfalls.

Staff Recommendation 6. Direct PGE to work collaboratively with Staff, stakeholders, peer utilities, and the Community Benefits and Impacts Advisory Groups (CBIAGs) in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRPs and CEPs by December 31, 2024. If PGE cannot complete this effort by this timeline, PGE should provide a detailed status update by the same date and explain how it will ensure that remaining issues are resolved as soon as practicable.

Staff Recommendation 7. Direct PGE to conclude its process to develop informational and portfolio community benefit indicators (CBIs) and provide baseline metrics prior to filing its next IRP/CEP Update. If PGE cannot complete this effort by this timeline, PGE should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

Staff Recommendation 8. Direct PGE to include a report on federal incentive implementation and its key impacts on the company's action plan and 2030 resource strategy with its next IRP/CEP Update.

Staff Recommendation 9. The Commission should decline to acknowledge PGE's avoided cost pricing inputs and direct PGE to recalculate its IRP inputs using an assumption of 75 percent for qualifying facility (QF) renewals and the QF success rate for Schedule 202 projects.

B. CUB

CUB is generally supportive of Staff's recommendations. Although CUB reiterates that renewable energy certificates (RECs) have no role in PGE meeting the emissions standards in HB 2021, CUB notes its appreciation for the commitment to ensuring accurate information about RECs is provided to Oregon-regulated voluntary purchasing programs in Order No. 24–002.

C. Energy Advocates

The Green Energy Institute at Lewis & Clark Law School, NW Energy Coalition, Climate Solutions, and Oregon Just Transition Alliance (collectively, Energy Advocates) support Staff's recommendations to acknowledge PGE's 2023 IRP subject to conditions; to decline to acknowledge PGE's CEP; to direct the company to revise and resubmit certain elements of the CEP by the next IRP Update; and direct the company to take additional actions.

Similar to CUB, the Energy Advocates support further action to clarify information distributed by utilities regarding RECs. The Energy Advocates request that the Commission protect purchasers of RECs by ensuring that utilities do not imply, "directly or indirectly, that Oregon retail customers receive the environmental, social, or economic benefits of renewable energy generation submitted to DEQ for HB 2021 compliance."[33] The Energy Advocates state that doing so would constitute double counting, as the utility "can only substantiate a portion of its electric supply with RECs."[34] The Energy Advocates further recommend that the CEP contain a chapter describing the GHG accounting method, and that the narrative include clarification that RECs are not retired on behalf of customers.

In addition, the Energy Advocates recommend requiring further clarity and information as part of Staff Recommendation 2 regarding long lead-time resources (to distinguish them from near-term resources); adding net metering, storage, and renewables to Staff Recommendation 5; taking note of the Columbia River Inter-Tribal Fish Commission's comment on the importance of engagement and partnership with tribal communities as described in Staff Recommendation 6; and supplementing Staff Recommendation 7, regarding the quantification of benefits of CBRE resources and CBIs, to include "community-based economic, reliability and resilience benefits as well as system benefits associated with reduced congestion and peak loads within their service territory."[35] The Energy Advocates note that least-cost energy supply should not be the sole determinant. The Energy Advocates assert that PGE needs to approach the CBIs and CBRE resources as a member of the community and not just as a provider of least-cost energy services.

D. Green Energy Institute

The Green Energy Institute (GEI) comments separately from the Energy Advocates to elaborate further on whether GHG emissions attributes are or may be excluded from Oregon RECs. GEI notes that our recent order regarding CEP plans, "left ambiguity

[33] Energy Advocates' Comments on Staff Report and Final Recommendations at 2 (Jan. 12, 2024).
[34] *Id.* at 3.
[35] *Id.* at 7.

around GHG emission claims and whether Oregon retail electricity customers can claim GHG reductions under HB 2021."[36]

GEI raises concerns about statements from Order No. 24-002 to highlight potential confusion about "whether HB 2021 compliance disaggregates RECs generated from resources reported for compliance purposes" and to raise the company's awareness of potential double counting concerns related to RECs acquired by PGE on behalf of Oregon retail electricity customers.[37]

E. AWEC

AWEC echoes Staff's concerns regarding a lack of supporting analysis regarding GHG emissions reduction modeling. AWEC agrees with Staff that PGE must update its IRP/CEP with hourly analysis of GHG emissions as described by Staff in Recommendation 3. However, AWEC disagrees with Staff's recommendation to acknowledge the CBRE action plan item, arguing that it may result in unnecessary cost and risk for ratepayers. In addition, AWEC states the Commission should condition its acknowledgment of the IRP/CEP on PGE providing additional information on the expected costs of its portfolio strategy so that HB 2021's cost cap can be effectively implemented.

F. Renewable Energy Coalition

Renewable Energy Coalition (Coalition) supports Staff's language on planning assumptions regarding QFs as clear and reasonable. The Coalition expresses support of Staff Recommendation 9 that the Commission "should decline to acknowledge PGE's avoided cost pricing inputs and direct PGE to recalculate its IRP inputs using an assumption of 75 percent for QF renewals and the QF success rate for Schedule 202 projects."[38]

G. NewSun

NewSun maintains that the Commission should decline to acknowledge both PGE's 2023 IRP and CEP, arguing that the plans are too related to reach different results—acknowledgment of one and not the other. NewSun points out that an IRP must comply with HB 2021, which obliges PGE (and other electric companies) to take actions "as soon as practicable" to reduce GHG emissions. NewSun states that PGE's 2023 IRP fails to do so by omitting feasible alternatives to reduce emissions—for example, a significantly heavier reliance on solar photovoltaic distributed generation. Moreover, NewSun

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[36] Green Energy Institute Comments at 3 (Jan. 12, 2024).
[37] *Id.* at 5.
[38] Staff Report, Attachment 1, Recommendation 9 at 27 (Dec. 14, 2023).

emphasizes that PGE relies on the existence and availability of future, hypothetical transmission capacity that may never be built, arguing that PGE has failed to prove this transmission will be online and available within the timeline set by HB 2021. Finally, NewSun highlights information from the Bonneville Power Administration showing that none of the 17,000 MW of pending transmission service requests were awarded to PGE's system as supporting its argument that there is no foreseeable path for transmission to achieve PGE's 2030 requirements under HB 2021.

H. Small Business Utility Advocates

The Small Business Utility Advocates (SBUA) comment that Staff Recommendation 1, regarding CBRE resource procurement, and the associated condition provide an opportunity for "deeper dialogue on the direct community benefits and impacts which provides a great platform to highlight how small businesses are defined within 'communities.'"[39] SBUA urges that "the [c]ompany and Commission [ ] use [zip code data and reports, and similar tools] to track weak spots of resiliency within the small business community."[40]

I. Renewable Northwest

Renewable Northwest (RNW) supports Staff's recommendations to acknowledge the IRP and not acknowledge the CEP. RNW notes that it expressed concern with PGE's emissions reductions forecast due to the absence of hourly modeling. RNW recommends that the Commission note in its order that offshore wind is a least-cost, least-risk resource. RNW further recommends that the Commission specifically acknowledge as reasonable specific long-term resources such as 1 GW of offshore wind and 2 GW of pumped hydro storage. RNW also notes its support for Staff's expectations for future IRP/CEP filings.

J. Columbia River Inter-Tribal Fish Commission

The Columbia River Inter-Tribal Fish Commission (CRITFC) supports Staff's energy efficiency and transmission efforts in these proceedings, noting the importance and benefits of energy efficiency, especially as it relates to "protecting fish, wildlife, and tribal treaty fisheries in the context of the energy system."[41] CRITFC further supports Staff Recommendation 4 to review and update avoided cost calculation metrics in UM 1893, and further enhancement of low-income investments with other energy resource investments. CRITFC also recommends quantifying more of the non-energy

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[39] SBUA Comments at 1 (Jan. 12, 2024).
[40] *Id.* at 2.
[41] Columbia River Inter-Tribal Fish Commission Round 2 Comments at 2 (Nov. 21, 2023).

benefits of efficiency, such as health benefits achieved by weatherization programs and advocates for replacing the total resource cost test with a societal test. CRITFC also notes its agreement with Staff Recommendation 7 to develop CBI criteria to measure environmental, health and community benefits.[42]

K. PGE

PGE modified its action plan in response to Staff and stakeholder comments prior to Staff's final report. In response to Staff's concerns about the lack of analysis regarding transmission upgrades, PGE agreed to conduct a transmission study before its next IRP/CEP update. Staff found this to be a reasonable starting point given the complexity of transmission analysis. PGE also added additional energy efficiency to its action plan as identified in its IRP/CEP analysis. In its final comments, PGE states it agrees with most of Staff's final recommendations. However, PGE does not agree with Staff's recommendation not to acknowledge its CEP, nor does it agree that it should recalculate avoided cost pricing inputs.

1. CEP

PGE opposes non-acknowledgment and disagrees with Staff and AWEC that it should conduct an hourly analysis of GHG emissions, arguing that hourly accounting has never been a requirement nor expectation expressed in UM 2225. Moreover, PGE contends that its CEP is in the public interest and meets HB 2021's statutory requirements, even if it is imperfect. PGE points to several previous orders where an IRP was acknowledged with instructions for improvement. PGE asserts that such an approach is appropriate here and that its CEP should be similarly considered, evaluated, and acknowledged.

PGE notes that it relied on the continued use of an annual energy position, which it states is consistent with earlier IRP modeling. PGE maintains that the annual energy position was a reasonable approach to approximate PGE's energy position and emissions for the first CEP. PGE states its commitment to making future advancements to its methodology. PGE states that it presented two additional analyses, which incorporated elements of hourly energy position modeling, but admits that the additional work undertaken "did not provide sufficient detail to meet Staff's expectations for this first CEP."[43] PGE requests that, in the event we adopt Staff's recommendation that the company revise and resubmit of elements of its CEP, that such resubmission be required as a part of the company's CEP/IRP update or PGE's next IRP/CEP filing.

[42] *Id.* at 7 (Nov. 21, 2023).
[43] PGE Comments on Staff Report and Final Recommendations at 7 (Jan. 12, 2024).

2. *Avoided Cost Pricing*

PGE disagrees with Staff Recommendation 9, which directs the company to recalculate its IRP inputs using an assumption of 75 percent for QF renewals and the QF success rate for Schedule 202 projects. PGE argues that using an assumption of 75 percent will have an immaterial impact on PGE's 2023 IRP/CEP. PGE requests that Staff's recommendation for an interim estimate of 75 percent for these assumptions be incorporated through an update to avoided cost pricing inputs for docket UM 1728 compliance.[44]

3. *PGE's Response to Other Staff Conditions*

PGE states that it generally agrees with Staff Recommendation 2 and associated conditions. PGE notes that it is amenable to the development of an RFI and agrees with Staff and Renewable Northwest that it is appropriate for PGE to conduct a separate process with a longer time horizon to identify resources in development and how PGE's investments in the grid may need to evolve to accommodate future resources. However, PGE notes that it will be in a near-continuous acquisition cycle as the company makes continual progress toward the HB 2021 targets, and therefore requests that completion of the RFI not serve as a contingency to PGE moving to meet capacity and energy needs identified in its action plan. PGE recommends Staff Recommendation 2 be modified to begin the long lead-time resource RFI prior to the issuance of its next RFP, to develop the RFI using a stakeholder process, and to provide sufficient time for review before proposing its next steps regarding actions needed to accommodate long lead-time resources.[45]

PGE notes agreement with Staff Recommendation 7 regarding the development of CBIs and states that it looks forward to "collaborating with stakeholders, utilities, and the CBIAGs, actively participating in evolving proposed improvements.[46]

Regarding Staff Recommendation 5, PGE notes that there is no SSR requirement prior to 2030. PGE states that it will conduct the recommended SSR analysis. The company explains that it considers this to be an informative exercise illustrating PGEs planned pathway to SSR compliance in 2030.

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[44] *In the Matter of Portland General Electric Company, Application to Update Schedule 201 Qualifying Facility Information*, Docket No. UM 1728.
[45] PGE Comments on Staff Report and Final Recommendations at 11-12 (Jan.12, 2024).
[46] *Id.* at 12.

VII. DISCUSSION OF PGE'S IRP AND CEP

We acknowledge PGE's 2023 IRP subject to the conditions recommended by Staff and further discussed and modified below. By acknowledging this IRP with conditions, we signal that there are issues to be resolved before certain actions are taken. However, the general direction of PGE's IRP is reasonable, as are the associated near-term action plan items. As an exception to our overall IRP acknowledgment, we accept Staff's recommendation not to acknowledge certain avoided cost inputs and we require their modification prior to PGE's post-IRP avoided cost filing.

Within the complexity of the current industry and policy landscape, PGE's IRP has drawn out significant issues and enabled discussion of paradigms associated with, and presented as alternatives to, its preferred resource strategies. Remaining adaptive and dynamic is a strength of the IRP process. New constraints and solutions invariably will emerge, and likely will emerge faster than ever before. We remind PGE of its responsibility to account for these changing conditions, and we are mindful of the need to maintain flexibility in the planning process in order to produce least-cost, least-risk solutions.

We adopt Staff's recommendation not to acknowledge the CEP and to require PGE to resubmit the CEP with modeling revisions, as discussed in further detail below. In declining to acknowledge PGE's CEP, we base our decision on the statutory requirement that we must determine that the plan is consistent with HB 2021's targets. Staff made a persuasive case, supported by nearly every other stakeholder in this process, that PGE's unwillingness to incorporate further analysis and update the preferred portfolio when material concerns were identified about whether it was sufficient to meet the compliance requirements left us with insufficient insight to determine the plan's consistency with HB 2021's targets. With our non-acknowledgment, we signal that Staff's concerns are legitimate and need to be taken seriously. We recognize that the timeline to meet HB 2021's requirements is short, and therefore we encourage the company to address this challenge by taking up the GHG and transmission modeling necessary to demonstrate that its plan, if executed, will be consistent with the targets and achieve an "affordable, reliable, and clean electricity system."

Our decision here is not meant to signal a lack of confidence that PGE's near-term actions are appropriate. Rather, our decision emphasizes that meeting HB 2021's targets and other goals will be a tremendous challenge and may require even more than PGE is currently planning. Long-term planning toward compliance must be supported with advanced analysis and open engagement with the barriers. A least cost, least risk plan to achieve compliance will be a balancing act that cannot shy away from the scale of that challenge or obscure it in modeling simplifications. Absent that analysis and engagement, the resulting plan may miss critical opportunities or risks by underestimating the need. Again, PGE's CEP marks the first occasion we have been tasked with reviewing a CEP in Oregon, and this process has served the purpose of highlighting areas where more work is needed.

We disagree with New Sun's assertion that the IRP and CEP are too tightly linked to acknowledge one and not the other. It is perhaps also a confusing outcome to those less intensively engaged in our processes. Our conclusion is that the IRP near-term actions set PGE on the path to compliance. In our deliberations, we asked whether there were additional actions PGE might take if, as Staff is concerned, its procurement targets for 2030 are too low or as New Sun argues, transmission solutions do not emerge. The actions PGE is taking, including the further analyses we require here, represent all the steps reasonably available to PGE at this time. Whether pursuing federal funding for projects, adopting additional energy efficiency, running very large resource procurement efforts in quick succession, or planning to obtain all small-scale projects PGE estimates to be realistically available, the company appears to be undertaking all steps that are currently available at reasonable cost. We note that HB 2021 has a cost cap we intend to explore further in docket UM 2273; that docket and future IRP/CEPs may provide more guidance on whether other, more costly actions should be taken in pursuit of HB 2021 compliance.

The IRP's preferred portfolio and underlying modeling appear to be a reasonable plan to achieve reliability while steeply cutting emissions and balancing customer risk and cost. Of course, the IRP is only a plan, and in this time of dynamic change, the contours of the preferred portfolio will continue to evolve from IRP to IRP along with the resource needs and the resources available to meet them. The CEP, in contrast, is meant to address HB 2021 compliance specifically. The lack of detailed modeling has left us, and stakeholders, unclear about whether there are feasibility or cost challenges beyond the actions PGE is already undertaking. While the plan describes extensive emissions reductions, representing positive forward movement, we cannot say whether it is enough to meet HB 2021 targets. Thus, we cannot acknowledge the plan.

We do not base our non-acknowledgment on lack of continual progress or a failure to satisfy the public interest standards listed in the statute. We agree with Staff that PGE's community engagement and action plan items are sufficient in the near-term to demonstrate continual progress (which we address in a separate order) and consistency with the public interest, subject to the accompanying conditions. Below, we discuss each of the specific conditions or requirements for future plans that we adopt, based largely on Staff's recommendations.

A. Conditions and Direction Related to PGE's Action Plan

1. Staff Recommendation 1: CBRE Actions

We agree with Staff's recommendation to acknowledge PGE's CBRE action item subject to the condition that PGE pursue the broader range of procurement actions that it identified in comments in this docket. We note AWEC's concerns and stress that our acknowledgment is based on IRP analysis quantitatively demonstrating that an achievable level of CBREs was a cost-competitive alternative to distant resources accessed by new transmission. Of course, only RFPs and other procurement strategies can illuminate whether actual CBRE eligibility and costs are similar to the assumptions in PGE's IRP analysis. In addition, we credit Staff's focus on thinking beyond RFP-based procurement; because RFPs do not work for all communities, it will be important to consider innovative, long-term engagement that integrates emerging revenue streams like those from ETO, Oregon Department of Energy, and the federal government.[47]

2. Staff Recommendation 2: Energy/Capacity Actions

We adopt, with modification, Staff's recommendation to acknowledge PGE's energy and capacity action items on the condition that, before issuing its next utility-scale RFP, PGE file a proposal to develop a long lead-time resource RFI via a stakeholder process in LC 80, facilitate a workshop on the RFI findings, and allow sufficient time for stakeholder review of its RFI before proposing its next steps. We agree with PGE's proposed revision to allow PGE to conduct future RFPs as it moves forward with the RFI process. Our expectation is that PGE will present and use the learnings from the RFI process in future procurements.

3. Transmission Analysis and Alternatives

The transmission analysis in PGE's 2023 IRP took a step forward relative to previous IRPs by explicitly recognizing that PGE's resource strategy—short-term and long-term—depends on transmission expansion. PGE provided significantly more information and stakeholder education on its transmission constraints and methods for addressing them in this IRP, and we appreciate that transparency. However, the 2023 IRP did not mature the transmission analysis sufficiently to match the urgency of PGE's need for transmission solutions.

For the shorter-term, the 2023 IRP recognized that PGE needs to take certain transmission actions in the action plan window to relieve constrained flowgates and

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[47] We note here that we also adopt Staff Recommendation 5 regarding SSRs, without modification, which was a part of our CBRE discussion.

maintain both reliable load service and a path to meeting PGE's 2030 HB 2021 requirements; however, PGE provided no meaningful analytical or decision-making framework for justifying the need and comparing alternatives for meeting the need. IRP acknowledgment of specific transmission action items implies reasonableness at the time of the analysis and provides support for a future determination of prudence. As a result, to support acknowledgment, we require a more complete analysis of the need and evaluation of the full range of available transmission solutions than was provided here, including non-wires alternatives when appropriate. PGE will need to present a risk-informed, cost-benefit analysis of all available transmission solutions for the 2030 time frame, including factors such as the associated timeline and cost risks, anticipated rate impacts, and the presence of longer-term or broader regional benefits. We require PGE to complete this shorter-term analysis of solutions to constraints that affect all resource delivery to PGE's load by the time it files its next IRP/CEP Update.

For the longer-term analysis, the 2023 IRP took appropriate steps toward pairing proxy resource alternatives with hypothetical proxy transmission expansion; however, PGE did not sufficiently explore the impact of cost and timing uncertainties surrounding large-scale regional transmission, nor alternatives it could pursue if least-cost, least-risk regional transmission alternatives do not materialize. Stakeholders argued, and we agree, that potential challenges with the timing and cost of large-scale transmission require PGE to stretch its paradigm to capture the full potential value of on-system and other local energy resources as alternatives to transmission expansion.[48] This more comprehensive analysis should help to inform PGE's decisions about participating in new regional scale transmission and its valuation of resources that do not require that transmission. It should assist PGE in demonstrating when and at what cost PGE's participation in new regional scale transmission is lower cost and lower risk than resources and load flexibility that do not require significant transmission expansion. Because this analysis addresses longer term considerations and will require more extensive scoping, we direct that it be completed and included in PGE's next IRP/CEP filing.

We welcome requests for Commission engagement in further scoping of this analysis and encourage Staff's engagement consistent with the expectations set forth in Staff's December 14, 2023, comments.[49] We clarify that our expectations for IRP analysis of major transmission resource needs and alternatives are not intended to intrude on the jurisdiction of the Federal Energy Regulatory Commission (FERC). We do not expect IRPs to analyze the core reliability upgrades developed in PGE's FERC-jurisdictional

[48] We do not intend to imply an expectation that such resources will supplant transmission entirely in a least-cost, least-risk portfolio. *See, e.g.*, Energy Systems Integration Group, "Modeling the Effects of Distributed Generation on Transmission Infrastructure Investment" (February 2024), available at https://www.esig.energy/distributed-generation-impact-on-transmission/.
[49] Staff Comments at 30.

transmission plans. However, for transmission expansion that is necessary to deliver generating resources from outside PGE's system to serve PGE's load, we stand by the requirement of our IRP Guidelines that transmission is a resource alternative and should be analyzed accordingly.

B. Direction for Future Planning

1. Staff Recommendation 4: Customer Actions and Guidance for Avoided Cost Update

We adopt Staff's recommendation to direct PGE to work with Staff to propose a new method for calculating avoided costs in docket UM 1893. In addition to Staff's recommendation, we direct PGE to collaborate with Staff and ETO to modernize the approach to long-term energy efficiency planning to use the best currently available information on energy efficiency and technical potential in future IRP and CEP updates.

2. Staff Recommendation 6 – Improved Engagement

We adopt Staff's recommendation to direct PGE to collaborate with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated collaborative to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs. We appreciate the strides PGE has made and recognize that bringing new stakeholders into utility planning takes sustained effort and focus.

3. Staff Recommendation 7 – CBI by Next Update

We adopt Staff's recommendation and reiterate our discussion that PGE must demonstrate development of CBIs to assist in our understanding tradeoffs between cost, risk, and community benefit, and when evaluating procurement decisions. We recognize that initial CBIs may not cover issues of concern to all communities, but we expect that some set of informational-only metrics be developed in time to be included with PGE's next RFP. If PGE cannot develop such metrics by its next IRP/CEP update, PGE must provide a detailed explanation of the barriers and constraints, along with a proposal for how and when PGE and its community stakeholders will be able to address them.

4. Staff Recommendation 8 – Report on Federal Incentives with Next Update

We adopt Staff's recommendation to direct PGE to include a report on federal incentive implementation with its next IRP/CEP update. We observe both that PGE has been successful in securing federal funds in initial rounds, and that there may be federal programs relevant to resource procurement and transmission development that have not been adequately explored. We recognize that there will always be uncertainty in the federal incentives landscape, particularly relative to long-term planning, but PGE should provide as much visibility into future opportunities as possible.

5. *Staff Recommendation 9 – QF Renewals and Success Rates*

We adopt Staff's recommendation to decline to acknowledge PGE's avoided cost pricing inputs and direct PGE to recalculate its IRP inputs using an assumption of 75 percent for QF renewals and the QF success rate for Schedule 202 projects. However, we read this narrowly and clarify that the avoided cost pricing inputs are not material to the IRP itself, but to the avoided cost price filing. We stress that the pricing inputs must be corrected due to their impact on the avoided cost price filing and decline to adopt PGE's recommendation to instead incorporate this change through an update.

6. *RECs Discussion in the Next IRP/CEP*

Between now and the filing of its next IRP/CEP, we direct PGE to engage in discussions with stakeholders on RECs to clarify how customers are meant to read and understand the information about clean energy and emissions reductions in the company's CEP. We adopt the Energy Advocates' recommendation to direct PGE to include a chapter of its next CEP addressing these issues.

7. *Cost Analysis/Cost Cap*

Planning for HB 2021 means planning not only for the emissions reduction targets, but also for the "affordable, clean, and reliable electricity system" that the statute expects regulated utilities to achieve. Thus, while significant questions remain to be addressed in UM 2273 about how we interpret and apply HB 2021's cost cap (including its relevance in future IRPs and CEPs), we do not need to answer those specific questions of statutory interpretation to know that we need the IRP and CEP process to deliver more information about rate impacts.

We must be able to rely on the resource planning process to guide steady continual progress on emissions reductions strategies but also to illuminate tradeoffs that may be required to avoid exacerbating near-term affordability concerns. These concerns will be relevant to our determination of the public interest in future CEP acknowledgment. Thus, despite the traditional focus of long-term planning on net present value of revenue requirement over the full planning horizon, going forward we expect that resource planning—at minimum in the identification of annual actions in the CEP—must include greater attention to near-term management of costs and rate pressures.

C. Conclusion

We thank Staff, PGE, and all stakeholders for providing a full record to help us address the most important issues to guide PGE's resource and HB 2021 strategy. In particular, we appreciate Staff's thoughtful work to present a manageable list of high priority items for Commission action, while making clear that Staff will continue to pursue additional expectations for future planning.

VIII. ORDER

IT IS ORDERED that:

1. Portland General Electric Company's 2023 Integrated Resource Plan is acknowledged subject to the conditions in the attached Appendix A; December 14, 2023, Staff Report, and as discussed at the January 25, 2024, Special Public Meeting, and detailed in this order.

2. The Clean Energy Plan filed by Portland General Electric Company is not acknowledged. We direct Portland General Electric Company to revise and resubmit certain elements of the Clean Energy Plan with its next IRP/CEP update.

3. We further direct the company to take additional actions as listed in Appendix A; December 14, 2023, Staff Report Attachment 1, and as modified and supplemented by our January 25, 2024 Special Public Meeting discussion, and addressed above.

Made, entered, and effective Apr 18 2024.

Megan W. Decker Chair	Letha Tawney Commissioner

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
SPECIAL PUBLIC MEETING DATE: January 18, 2024

REGULAR _X_ **CONSENT** ____ **EFFECTIVE DATE** ______ **N/A** ______

DATE: December 14, 2023

TO: Public Utility Commission

FROM: Sudeshna Pal

THROUGH: Caroline Moore

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. LC 80)
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge Portland General Electric's (PGE or Company) 2023 Integrated Resource Plan (IRP) subject to conditions, decline to acknowledge the Clean Energy Plan (CEP) and direct the Company to revise and resubmit certain elements of the CEP by the next IRP Update, and direct the Company to take additional actions.

The Public Utility Commission of Oregon Staff's (Staff) proposed conditions for acknowledgement, recommendations for PGE to revise and resubmit the CEP, and recommendations to direct the Company to take additional actions are outlined in Attachment 1 and discussed in detail in this memo.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (Commission) should acknowledge PGE's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PGE's CEP or decline to acknowledge the CEP and direct the Company to revise and resubmit certain portions of the plan.

Whether the Commission should direct PGE to take any additional actions prior to filing its next IRP or IRP Update or CEP.

Applicable Law

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[1] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of "IRP Guidelines" to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), and 08-339 clarify the procedural steps and substantive analysis required of Oregon's regulated utilities before the Commission considers acknowledgement of a utility's resource plan.[2] These orders are incorporated in OAR 860-027-0400(2), which requires any IRP to satisfy their requirements.

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[3] Further, the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to four years.[4] The utility's IRP should satisfy the IRP Guidelines and Commission rules for its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives reviewed to meet its future resource needs, and its near-term Action Plan to achieve the IRP goal of selecting the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[5] This is often referred to as the "least cost/least risk portfolio."

The Commission reviews the utility's plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonably based on the information available at the time.[6] However, the Commission explains: "We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option

[1] Order No. 89-507.
[2] Order Nos. 07-002 and 07-047. Additional refinements to the process have been adopted: See Order No. 08-339 (IRP Guideline 8 was later refined to specify how utilities should treat carbon dioxide (CO2) risk in their IRP analysis); Order No. 12-013 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[3] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.
[4] Order No. 14-415 at 3.
[5] Order No. 07-002 at 1-2.
[6] *Id.* at 1.

for its customers."[7] The Commission may also provide direction on additional analysis or actions for the next IRP or IRP Update.[8]

In 2021, the legislature passed House Bill 2021 Oregon House Bill (HB) 2021, codified as ORS 469A.400 to 469A.475, which requires the state's large investor-owned electric utilities (IOUs) and electricity service suppliers (ESSs) to decarbonize their retail electricity sales with consideration for direct benefits to local communities.

ORS 469A.415 requires large electric IOUs to, "develop a clean energy plan for meeting the clean energy targets set forth in ORS 469A.410 concurrent with the development of each integrated resource plan," and file the plan with the Commission and Oregon Department of Environmental Quality (DEQ).

ORS 469A.420 outlines the requirements and considerations for the Commission to acknowledge the CEP "...if the commission finds the plan to be in the public interest and consistent with the clean energy targets..."

In addition, ORS 469A.415(6) requires the Commission to ensure that the utilities demonstrate continual progress within the CEP planning period toward meeting the clean energy targets and are taking actions as soon as practicable to reduce emissions at reasonable cost to retail electricity consumers.

Additional requirements for the filing, review, and update of IRPs and CEPs are provided in OAR 860-027-0400.

<u>Analysis</u>

Background
Portland General Electric Company (PGE or the Company) filed its combined 2023 Integrated Resource Plan and Clean Energy Plan (IRP/CEP or plan) with Oregon Public Utility Commission on March 31, 2023. PGE is the first electric utility in Oregon to file its long-term resource plan following the passage of Oregon House Bill 2021 (HB 2021). Three rounds of comments have been provided by Staff, interested parties, and the Company. Round 0 comments provided preliminary notes about improvements PGE could make in advance of participants' in-depth review of the IRP/CEP. Round 1 comments evaluated the reasonableness of the plan and explored acknowledgement considerations. Round 2 comments focused on Staff's recommendations for Commission acknowledgement of the IRP/CEP.

[7] *Id.*
[8] OAR 860-027-0400(7), (10).

Staff is grateful for the engagement and contributions made in this process, including written comments from Alliance of Western Energy Consumers (AWEC), Columbia River Inter-Tribal Fish Commission (CRITFC), Oregon Citizens' Utility Board (CUB), Deep Blue Pacific Wind, Elizabeth Graser-Lindsey, Energy Advocates, Green Energy Institute (GEI), Grid United LLC, NewSun Energy LLC (NewSun), Northwest Energy Coalition (NWEC), Oregon Solar + Storage Industries Association (OSSIA), Renewable Energy Coalition (REC), Renewable Northwest (RNW), and Swan Lake and Goldendale Energy Storage Projects.

Staff also thanks PGE for embracing many of Staff's draft recommendations, its willingness to consider inputs provided by a broad range of participants, and commitment to continue working on improving its planning tools and approaches moving forward. PGE's recent updates to its IRP/CEP address several concerns raised by Staff and stakeholders. Specifically, the adjustment to energy and capacity needs based on inclusion of optimum energy efficiency resources and contract renewal updates. In addition, adjustments to market capacity assumptions in modeling proxy transmission resources have boosted Staff's confidence that the current IRP/CEP is capturing a realistic estimate of what is required to support HB 2021 compliance.

The remainder of this Staff report reflects on the key decarbonization planning insights gained, expresses support for the Company's revised near-term actions, and makes recommendations for PGE to better demonstrate a credible path to a reliable, affordable, equitable and decarbonized system.

IRP/CEP Overview
PGE has estimated significant growth in its energy and capacity needs over the next two decades driven by the transition to non-emitting energy and growing demand from industry and electrification. At the same time, the Company iterated on its supply and demand side needs based on input from participants in the IRP/CEP review investigation.

The Company's latest revision to its plan projects 1254 MWa of energy and 1538 MW Summer, 1284 MW Winter MW of capacity additions are needed to support the 2030 emissions reduction targets in an affordable and reliable manner. To make progress toward this, PGE identified the following acquisition goals in the Action Plan (2024–2028):

- 251 MWa of energy per year (previously 261 MWa)
- 905 MW of summer capacity (previously 944 MW)
- 787 MW of winter capacity respectively (previously 827 MW)

Through portfolio analysis, the Company explored the role that different resource types could play in the Company's long-term strategy, such as community-based resources, demand-side resources, emerging and long lead time resources, transmission expansion, and access to markets. Through this analysis, the Company identified a preferred portfolio of annual resource actions through 2043. From this, the Company identified a set of near-term action items that will best position the Company to achieve the balance of cost, risk, emissions reductions, and community impacts and benefits reflected in the preferred portfolio. The Action Plan is summarized in Table 1.

Table 1. Summary of PGE's Action Plan for 2024 - 2028

		LC 80 Addendum	PGE Round 2 Comments
Customer Actions	Acquire all cost-effective energy efficiency **plus additional quantities identified in the CEP/IRP analysis**	150 MWa Cumulative 2024-2028	**182** MWa Cumulative 2024 - 2028
	Incorporate customer demand response.	211 MW Summer and 158 MW winter by 2028	Unchanged
CBRE Action	Issue RFP for all available and qualifying CBRE resources.	66 MW by 2026	Unchanged
Energy Action	Conduct one or more RFPs to acquire sufficient capacity to meet forecasted 2028 needs.	261 MWa (1307 MWa/5 total years) per year through 2028	**251** MWa (**1254** MWa/5 total years) per year through 2028
Capacity Action	Conduct one or more RFPs to acquire sufficient capacity to meet forecasted 2028 needs.	944 MW summer and 827 MW winter	**905** MW Summer and **787** MW winter
Transmission Actions	Pursue options to alleviate congestion on the South of Allston (SoA) flowgate.	n/a	Clarified to focus on developing a comprehensive transmission study
	Explore options to upgrade the Bethel-Round Butte line (from 230 to 500kV).	n/a	Clarified to focus on developing a comprehensive transmission study

In addition to providing PGE's near-term goals in the Action Plan, the IRP/CEP process highlighted several important insights for PGE's path to decarbonization, as summarized below:

- Pursuing available supply and demand-side technologies in a manner that is responsive to the modern landscape is a clear low-regrets near-term action.
- HB 2021 and transmission constraints may require changes in the way we consider on-system resources as a resource option, particularly energy efficiency. Cost effectiveness methodologies may need to evolve to recognize this additional value.
- Uncertainty around load projections, driven by electrification of other sectors and growth in certain industries, is a key challenge in decarbonization planning.
- Access to regional markets and associated transmission may be a critical dependency of PGE's compliance strategy in the 2030s.
- Access to emerging non-emitting capacity technologies may be a critical dependency of PGE's 2040 compliance strategy.
- Overcoming transmissions constraints will require creativity, collaboration, and consideration of a portfolio of transmission expansion investments and alternative solutions such as on-system resources.
- It is important for PGE to become more quantitative with its evaluation of community benefits and impacts and the role of community-based resources.

Finally, this first attempt at resource planning in the current landscape resulted in many innovations and highlighted how difficult it is to develop a meaningful and accessible resource strategy using the tools and information available today. While Staff focuses its recommendations on acknowledgement considerations and critical near-term implementation direction, the need to evolve both planning and procurement strategies is clear. Staff looks forward to applying the lessons learned in this initial IRP/CEP review to the further development of the Commission's planning and procurement policies expected in 2024.

Staff Recommendations
The final recommendations in this Staff report reflect a collaborative effort among a diverse group of participants who share a common purpose of ensuring that PGE's Oregon customers receive clean, affordable, equitable and reliable electricity services. Although the planning period is over a 20-year timeframe, HB 2021 sets a target for PGE to reduce emissions to 80 percent below its baseline level in 2030. This helped

focus much of the discussion in this docket on the non-emitting resources that need to be in place for PGE to reduce emissions below the 2030 target.

On October 24, 2023, Staff released its draft recommendations for acknowledgement of PGE's Action Plan, Long-term IRP/CEP Strategy, and a handful of other resource strategy issues. PGE and stakeholders provided meaningful feedback on these recommendations on November 21, 2023. Staff has used this feedback to develop its final recommendations to the Commission.

Staff's final recommendations fall into three categories: IRP Acknowledgement, CEP Acknowledgement, and Other Issues. These recommendations are summarized in Attachment 1 and explained in further detail in the sections below.

Staff Note: The first IRP/CEP review process surfaced many learnings and Staff expectations for future planning processes. To focus Staff's recommendations on key decisions for acknowledgment of this IRP and CEP, Staff has documented these expectations separately in Attachment 2. Staff plans to raise these concepts for further exploration in discussions about future IRP/CEPs and clarifies that this list is not being presented for Commission approval. To the extent that the Commission wishes to comment on these concepts or include direction to implement them in its acknowledgment order, Staff believes that they have this flexibility.

IRP Acknowledgement

PGE's Updated Action items in its November 21, 2023, LC 80 filing include the following:

Customer Actions

- Acquire all cost-effective energy efficiency plus additional quantities identified in CEP/IRP analysis, which is, 182 MWa cumulative EE between 2024–2028.
- Incorporate customer demand response of 211 MW summer and 158 MW winter demand response by 2028.

CBRE Action

- Issue RFP for all available and qualifying CBRE resources amounting to 66 MW by 2026.

Energy Action

- Conduct one or more RFPs to acquire sufficient energy to position PGE to meet the forecasted 2030 needs, estimated to be 251 MWa (1307 MWa/5 total years) per year through 2028.

Capacity Action

- Conduct one or more RFPs to acquire sufficient capacity to meet forecasted 2028 needs of 905 MW summer capacity and 787 MW winter capacity.

Transmission Action

- Develop a comprehensive transmission study regarding options to alleviate congestion on the South of Allston (SoA) flowgate.
- Developing a comprehensive transmission study to explore options to upgrade the Bethel-Round Butte line from 230 to 500 kV.

Staff concludes that PGE's 2023 IRP meets the applicable requirements of the guidelines established in OAR 860-027-0400(2), and Staff recommends acknowledgement of the IRP **subject to the conditions** identified below.

1. Acknowledge PGE's CBRE Action Item subject to the condition that PGE pursue the broader range of procurement actions that it identified in comments in this docket.
2. Acknowledge PGE's Energy and Capacity Action Items subject to the following condition:

   Before issuing its next utility-scale RFP, PGE will file a proposal for a Long Lead Time Resource RFI developed via a stakeholder process in LC 80 and facilitate a stakeholder discussion (workshop) on the findings of the RFI and allow sufficient time for stakeholder review of its RFI before proposing its next steps.

Customer Actions
The Company's approach to establishing energy efficiency (EE) acquisition targets was a central point of discussion. PGE's portfolio analysis identified an additional 53 MWa of energy efficiency to be part of the least-cost least-risk portfolio. However, the Company decided not to pursue this additional amount citing near-term rate impacts and implementation challenges. Staff, stakeholders, and CRITFC advocated for inclusion of the additional least cost, least risk EE in PGE's acquisition targets and the Company has engaged in a discussion of potential solutions to its initial concerns, such as securitization of EE investments to lower the near-term cost burden on consumers. Staff believes that there is general agreement that EE resources provide a unique value under current policies and system conditions that may not be reflected in the traditional EE planning and procurement framework. Staff appreciates participants' commitment to modernizing these frameworks and addresses the EE avoided cost framework in more detail at the end of this section.

PGE's most recent analysis (PGE Round 2 Comments) shows that adding 53 MWa of energy efficiency to its Addendum preferred portfolio lowers its net present value of revenue requirement (NPVRR) by approximately $532 million.[9] The Company has also committed to taking the following actions to address near-term costs and implementation challenges:

1. Discussing securitization and other rate making mechanisms to address the magnitude and timing of EE costs to customers, for above-traditional levels of EE investments.
2. Supporting Energy Trust to develop guiding principles in addition to the existing cost-effectiveness framework to actively consider utility rate impacts.
3. Creating an appropriate mechanism, consistent with the above guiding principles, to set targets for outside funding and requirements for regular reporting.
4. Including PGE in formalizing the divisions of labor and funding allocations established between Energy Trust of Oregon (ETO) other entities such as ODOE, DEQ, PCEF and NEEA.
5. Exploring the co-deployment of flexible load and EE programs focusing on how these programs can help customers participating in the Income Qualified Bill Discount (IQBD).[10]

Based on these commitments and the Company's increasing willingness to engage in discussions about evolving EE planning and procurement frameworks to provide for the best balance of cost, risk, community impacts, and pace of GHG, Staff believes that the Company's revised Customer Action Item is reasonable and its draft acknowledgement conditions for the Customer Action Items can be converted to Staff expectations:

- PGE pursues all cost-effective EE, which means pursuing all EE identified through the IRP/CEP as providing for the best balance of cost, risk, community impacts, and pace of GHG reductions. This includes the additional 53MWa of energy efficiency that PGE identified as cost-effective in the current IRP/CEP.
- PGE engages collaboratively in addressing EE implementation issues with Staff, Stakeholders, and Energy Trust of Oregon, including Energy Trust's 2024 budget, further exploration of securitization of EE, and a 2024 effort to update avoided cost methods to include the full value of HB 2021 compliance and avoided transmission.

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[9] PGE Response to Staff's Round 2 Comments and Recommendations (hereinto referred to as "PGE Round 2 Comments"), p.33.
[10] Id., p.17.

CBRE Action
Through the UM 2225 Clean Energy Plan Investigation, the Commission recognized the importance of articulating the role that community-based resources (CBREs) will play in HB 2021 compliance through the CEP.[11] PGE includes 155 MW of CBRE resources in its preferred portfolio and plans on acquiring 66 MW by 2026. PGE's analysis and inclusion of CBRE is a novel concept that prompted valuable discussion. In particular, that the development of CBREs will likely require a multipronged procurement approach and that it should be a priority for PGE to be more quantitative about community benefits and impacts and CBREs as a resource option.

Several stakeholders including RNW and Energy Advocates support Staff's draft recommendation to acknowledge PGE's CBRE Action Item. Energy Advocates and New Sun also suggest that PGE's modeling may have undershot the optimal acquisition target, pointing to the need to account for additional benefits from CBREs in modeling and recommends either a sensitivity (Energy Advocates) test of or consideration of uncapped CBRE or 125 percent of CBRE potential in portfolio modeling.

AWEC recommends that the Commission not adopt Staff's recommendation to acknowledge the CBRE Action Item on grounds of potential rate impacts on customers who are already burdened by ongoing and future utility rate increases due to various factors including high decarbonization costs. AWEC points out the lack of analytical support for CBRE modeling assumptions in PGE's portfolio analysis and recommends that CBRE resources should be directly comparable to non-CBRE resources if PGE is going to pursue Request for Proposals for these resources.

As reflected in prior Staff comments, Staff supports the CBRE Action Item as an initial attempt at responding to important policy direction. The Energy Advocates, NewSun, and AWEC's concerns all highlight the importance of being more quantitative about CBREs in future IRP modeling and considering cost-management strategies during ongoing implementation of the CBRE target. Without more sophisticated modeling approaches, arguments about that get more specific about the appropriate CBRE level target are difficult to substantiate. Staff believes that PGE has put forth a meaningful quantity and commits to being comprehensive and collaborative in its acquisition strategies. Staff also notes that affordability has several dimensions, including the differential burdens of rate increases and longstanding distributional inequities in the ability to access clean energy options prior to HB 2021. Staff continues to explore these complicated issues through its implementation of HB 2475 alongside HB 2021.

PGE also agreed to Staff's draft recommendation, and it remains unchanged in Staff's final recommendations.

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[11] See Docket UM 2225 Order 22-390.

Staff Recommendation 1. Acknowledge PGE's CBRE Action Item subject to the condition that PGE pursue the broader range of procurement actions that it identified in comments in this docket.

Energy and Capacity Action
PGE proposes to perform ongoing, flexible Request for Proposals (RFPs) for non-emitting energy and capacity resources to complement its other resource actions. The Company filed a description of this strategy in its 2023 All-Source Request for Proposals docket[12] and provided a final projection of the energy and capacity procurements in its Round 2 comments:

- Energy target: Target 251 MWa per year, up to 1254 MWa by 2028.
- Capacity target: Seek 905 MW of summer and 787 MW in winter by 2028.

With HB 2021 requirements and the level of uncertainty underlying the IRP analysis, Staff agrees that issuing a series of adaptive RFPs is a low-regrets resource strategy. The trade-off of this strategy is an acute need for transparency, Commission touchpoints, confidence in the Company's bid scoring and contract negotiation approach, and ongoing reexamination of costs and resource needs. While some of this may be addressed in revisions to the Commission's planning and procurement framework in 2024, much of this work is likely to take place in individual procurement dockets.

In its draft recommendations, Staff recommended that PGE reflect the procurement of additional EE in its final energy and capacity actions. PGE revised its targets to reflect the 53MWa of additional EE in its preferred portfolio and recent bilateral contract renewals. PGE expressed its plan to initiate a process around procurement of long-lead time resources in the first quarter of 2024 and issue a Request for Information (RFI) around that time. Staff appreciates PGE making this adjustment.

PGE's revised preferred portfolio includes the acquisition of offshore wind resources beginning in 2032. RNW highlighted challenges that PGE may face procuring long-lead time (LLT) resources, like offshore wind, under the traditional RFP approach. In response, Staff's draft recommendation for acknowledgement of the Energy and Capacity Action Items included a condition for PGE to issue an RFI for LLT resources and use the results to propose RFP actions that will help the Company access beneficial LLTs.

[12] *See* Docket No. UM 2274, PGE'S Planning and Procurement Forecast, July 14. 2023.

PGE expresses support for this recommendation and anticipates issuing the RFI to by the end of Q1 2024 or providing an update filing in LC 80 to discuss progress and next steps.[13] RNW's comment provides additional insights into the proposed long-lead time development process and highlight the need to incorporate stakeholder feedback in the design of the RFI and allow sufficient time for stakeholder review of the RFI findings prior to including them in PGE's subsequent all-source RFP. Staff agrees this is an important part of the process and adjusted its recommendation to reflect the significance of stakeholder input in RFI and RFP processes. RNW also suggests including transmission as a long lead time resource and requests the Commission to acknowledge this resource as such. Staff believes that transmission development should be a separate exercise since it is notably different from any other supply or demand side resource development, and an RFI may not be the most appropriate way to get a comprehensive sense for potential and realistic transmission projects. PGE commits to provide comprehensive transmission studies related to congestion on its system. Staff considers that to be a good starting point and hopes to learn from the studies before moving on to the next steps.

Energy Advocates point out the importance of including non-price scoring factors in RFPs, which aligns with a Staff expectation listed in Attachment 2: Include a proposal for the use of CBIs in scoring the next utility-scale RFP bids.

Several participants including CUB, Energy Advocates, and RNW are generally supportive of Staff's recommendation to acknowledge the Energy and Capacity Action Items. Staff updates its final recommendation to reflect PGE's updated targets, RFI commitments and additional discussion in Round 2 comments.

Staff Recommendation 2. Acknowledge PGE's Energy and Capacity Action Items subject to the following condition:

Before issuing its next utility-scale RFP, PGE will file a proposal for a Long Lead Time Resource RFI developed via a stakeholder process in LC 80 and facilitate a stakeholder discussion (workshop) on the findings of the RFI and allow sufficient time for stakeholder review of its RFI before proposing its next steps.

Transmission Action

This IRP/CEP represents PGE's first time endogenously modeling transmission actions alongside resource actions in portfolio analysis. PGE's original action items included its plan to pursue and explore options to alleviate congestion on the South of Allston transmission route and upgrade the Bethel-Round Butte transmission line. PGE's IRP/CEP highlights transmission expansion as a critical dependency of its resource

[13] PGE Round 2 Comments, p. 5.

strategy and many parties discussed the need for creativity and collaboration to overcome the challenges presented. However, several stakeholders and Staff pointed out the vagueness in the action items and their apparent disconnection with PGE's portfolio analysis. On these grounds, Staff and several stakeholders did not believe the transmission actions to be appropriate for Commission acknowledgement. Staff outlined some of its expectations for providing meaningful transmission analysis, including: a clear description of the drivers, a clear description of the investment options, detailed cost/benefit analysis, and exploration of alternatives.[14]

NewSun did not respond to Staff's draft recommendations but similarly urges the Commission to direct PGE to reflect more feasible transmission options and timelines. CRITFC supports the need for more comprehensive transmission planning and points out that the recent agreement between the Confederated Tribes of Warm Springs and PGE regarding the 230 kV Bethel-Round Butte transmission line upgrade project marks progress towards achieving HB 2021's broader goals of building partnerships with communities who are ultimately impacted by these infrastructure investments.

PGE responded to these concerns and modified the action items as follows:

> PGE will perform a transmission study in advance of the next IRP update analyzing the potential impacts and benefits of transfer capability along constrained transmission paths within PGE's system, in the Pacific Northwest, and the market and resource potential of importing generation from inter-regional climate zones and markets that PGE does not typically access today. The study will specifically analyze the benefits and impacts of Trojan to Harborton and Bethel to Round Butte, as potential solutions, to alleviate congestion on South of Allston and Cross Cascades.[15]

PGE provides additional details of its proposed study approach and Staff believes that this framework is likely to provide better information to guide future decision-making. Staff appreciates PGE's plan to conduct the much-needed study of transmission that fully evaluates transmission constraints on its system and opportunities for alleviation prior to its next IRP. Staff believes this is a reasonable starting point given the complexity of this analysis and looks forward to the comprehensive transmission plans that PGE commits to provide in its near-term action plan, prior to its next IRP Update.

[14] Staff also highlighted a few alternatives, including creative use of transmission rights, redirects, and on-system resources. Staff also proposed stacking investments and other alternatives to relieve a constraint.
[15] PGE Round 2 Comments, p. 13.

CEP Acknowledgement

Staff believes that the Company's first CEP reflects meaningful engagement with the key elements of HB 2021. The CEP includes annual goals for actions that make progress towards meeting the clean energy targets, a demonstration of anticipated emissions reductions through 2040, resource portfolio cost and risk analyses, consideration of community benefits and impacts, accounting for federal incentives, and evaluating the effect of its resource plan on system reliability. Staff also appreciates PGE's consideration of community-based renewable resources (including resilient resources) and its efforts to engage community in developing its first CEP.

As the first attempt at a CEP, Staff and stakeholders pointed out several vulnerabilities in considering the economic and technological feasibility of PGE's strategy for reaching the 2030 emissions reduction targets and beyond. In the following section, Staff provides a brief description of these issues and how PGE's IRP/CEP has evolved since the beginning of this process. PGE has addressed several of these concerns and revised its analysis and Action Plan accordingly. Opportunities for high priority improvements in future plans are presented in Attachment 2. One core issue with PGE's CEP remains. Therefore, Staff recommends that the Commission should decline to acknowledge the CEP and direct PGE to revise and resubmit elements of its plan to provide sufficient confidence that PGE has shown a reasonable upper bound of actions needed to meet its 2030 emissions reduction targets.

Staff note: The issues described in this section should not be interpreted as concerns about the presence of any particular resource action in the preferred portfolio. For example, Staff is supportive of the modeling improvements that resulted in the inclusion of offshore wind technology in the preferred portfolio and in making its recommendation does not intend to suggest that the Commission decline to acknowledge the presence of offshore wind in the preferred portfolio.

Emissions Modeling Concerns

Staff, RNW, and AWEC have extensively discussed the need for an hourly dispatch analysis to confirm PGE's GHG emissions projections and its ability to comply with HB 2021. Parties pointed out that PGE's annual approximations neglect important aspects of system operations that may impact the Company's annual GHG emissions and what they report to DEQ. PGE's plan relies on the ability to access non-emitting energy from the market during hours when PGE's load exceeds its available non-emitting generation, at no price premium. Staff is concerned that this assumption results in an overly optimistic assessment of the resource actions that may be needed to reliably meet its customers' needs and its emissions reduction targets. While PGE has been open to exploring these concerns and providing additional analysis, Staff continues to have concerns that PGE's IRP/CEP assumes this market depth into the future without any supporting analysis. In particular, Staff and stakeholders have expressed concern that the hours of PGE's system surplus and shortfalls generally coincide with those expected across the broader region, and that this alignment may severely limit PGE's ability to rely on the market for additional non-emitting generation to serve load when it is needed.

The sufficiency and timing of market depth for excess non-emitting generation into the future is a central question when planning for a decarbonized system. Staff agrees that it is reasonable to assume that there will be periods with excess renewable generation available from the market and that it's possible to estimate the timing and depth of these with some reasonableness. However, there is a point at which simplifying assumptions about market depth damage the integrity of the planning insights. To this end, Staff does not believe that it is appropriate to assume that these periods will necessarily align with PGE's periods of need with 100 percent certainty. Instead, Staff continues to urge PGE to use industry standard approaches, such as production cost simulation, on which its IRP already relies, to estimate the hourly performance of its resource portfolio and the interactions with the broader Western electricity market in order to estimate GHG emissions.

In the IRP/CEP review process, Staff requested that PGE perform additional analysis to identify the scale at which the Company may be underestimating the resources needed to achieve its emissions reductions. PGE raised several concerns with using the production cost modeling approach. Staff does not disagree that there are potential vulnerabilities associated with any production cost simulation and that IRPs are generally subject to these vulnerabilities, but production cost simulation remains the industry standard for answering these types of questions. Production cost modeling has been used extensively by utilities, researchers, and independent organizations to grapple with questions related to renewable integration, renewable overgeneration, and decarbonization for years. PGE also raised a reasonable concern about the strain that Staff's request placed on planning personnel. Staff is concerned about the Company's prioritization of its planning team resources given the central role that planning plays in meeting what is likely its most significant regulatory requirement in the coming decades. However, this report focuses on the substantive merits of this analysis.

Despite objections, the Company conducted an hourly analysis of the Preferred Portfolio using similar methodologies and assumptions to those proposed by Staff. PGE's hourly analysis yielded 2.51 mmtCO2e in 2030.[16] This finding corroborates Staff's concern that if PGE is not able to access adequate non-emitting generation from

[16] PGE Round 2 Comments, p. 24.

the market when it is needed, the emissions resulting from the Company's preferred portfolio could fall outside of the Company's 1.62 mmtCO2e target.[17]

PGE also conducted analysis into the potential for additional resources to help bring the GHG emissions from its hourly analysis down. PGE tested individual resource additions and found that unrealistically large capacities (i.e. 43-101 GW of additional wind, over 5 GW of hour-hour batteries, or over 300 MWa of additional energy efficiency) would be needed if PGE were to pursue only one type of resource. PGE also presents one portfolio of additional solutions (500 MW each of wind, solar, and four-hour batteries + 50MWa EE) that seems to achieve most of the needed reductions, but the Company does not report out the resulting emissions, discuss how this portfolio was developed, or explore whether different combinations of resources might yield lower costs. It is not clear whether PGE's findings reflect real limitations on its system, or whether they are in part due to the limitations in the GHG accounting construct in the Intermediary GHG model.

Nevertheless, Staff appreciates that this exercise has moved the discussion into a space where useful insights can be discussed. For example, Staff is reassured that combining diverse resources significantly reduced the amount of capacity needed to further bring down emissions. Staff is confident that PGE can find better portfolio solutions if given additional time.

Transmission Access

PGE responded to Staff's recommendation to remove WY and NV proxy transmission resources from the preferred portfolio by removing the perfect capacity modeling assumption associated with WY and NV proxy transmission resources. This addresses part of Staff's concerns along with concerns raised by AWEC, RNW, NewSun, CUB, and Energy Advocates. Staff appreciates PGE's response in this regard and notes that PGE reports a decline in the NPVRR of its Preferred Portfolio by approximately $5.3 billion due to transmission assumption and EE adjustments.

By removing the perfect capacity assumption for the WY and NV proxy resources and conducting hourly analysis to estimate their GHG emission in 2030, PGE's response in its Round 2 Comments largely addressed two of the three conditions attached to Staff's Draft Recommendation.[18] However, PGE did not endorse the findings of its hourly analysis nor did the Company update the Preferred Portfolio or identify any other enhancements to the resource strategy based on the insights provided by the hourly

[17] To help justify the importance of examining the potential scale of this modeling issue, Staff provided its own rough approximation in comments and estimated a range of 2.4-3.5 mmtCO2e, which provides a similar insight in terms of magnitude.
[18] See Recommendation 6 in Staff's Round 2 Comments, p. 16.

analysis. Staff remains concerned that PGE's Preferred Portfolio may not yield the GHG emissions reductions that the Company claims without incremental solutions that mitigate renewable balancing challenges, such as additional energy efficiency, energy storage, and more diverse renewables.

CEP Acknowledgement Recommendation
Several stakeholders including CUB, Energy Advocates, RNW, and AWEC have expressed support for Staff's draft recommendation to decline to acknowledge the CEP and direct the Company to revise and resubmit so that the Preferred Portfolio reflects the insights derived from the hourly analysis and removal of the proxy transmission.

PGE intends to work with Staff and stakeholders to address several methodological questions around its emissions analysis and hopes to find an appropriate way to verify whether its Preferred Portfolio can credibly meet the emissions targets. Staff realizes PGE may need more time to present an analysis that addresses modeling concerns raised from the beginning of this process by Staff and several stakeholders, and therefore believes that PGE would find a reasonable approach by the IRP Update that would be due for filing in 2025.

The Preferred Portfolio represents PGE's estimate of the minimum actions needed to achieve the emissions reduction targets, including the 2030 target. Staff believes the action plan associated with this portfolio will result in continual progress toward the 2030 target in the immediate future. Staff, however, will continue to lack confidence that these projected emissions reductions will ultimately result in compliance with the emissions reduction targets until the Company provides an opportunity for Staff and the Commission to consider the results of the requested portfolio analysis. Due to the nature of the CEP, Staff believes that it is important for the Company to outline a portfolio of actions that can credibly enable the desired emissions reductions. Staff continues to believe that this accuracy is needed to fully acknowledge the CEP.

Staff Recommendation 3. Decline to acknowledge PGE's expected reduction of greenhouse gas emissions in the Clean Energy Plan as credible based on the preferred portfolio and direct the Company to make the following revisions and resubmit the revised plan before its IRP/CEP Update in 2025:

- *PGE shall conduct hourly production cost simulation of its preferred portfolio under the Reference Case in a manner that separately tracks hourly purchases and hourly sales. PGE will use this analysis to revise its GHG emissions forecast and to revise its submission to DEQ.*

- *PGE shall update the Preferred Portfolio accordingly and provide a brief narrative explanation of the key planning insights derived from this exercise.*

Other Issues

The section below outlines a limited set of issues Staff or other participants raised for Commission direction.

Avoided Cost – Energy Efficiency

Discussion of the Customer Action Item highlighted a near-term need to update the EE avoided cost methodology in order to effectuate Staff's expectations for better EE planning and procurement. Energy Advocates pointed out the need to reevaluate prior practices in determining cost-effectiveness of energy efficiency in the light of HB 2021. PGE noted, and Staff agrees, deficiencies in the avoided cost calculation methodology in the current EE Avoided Cost Methodology docket (Docket No. UM 1893) which has not kept up with Oregon's decarbonization policies. Staff's draft recommendations called for PGE to propose an update to the current methods in this IRP/CEP review docket as a transparent launching point for an effort to update the methods in the appropriate docket. Several participants including CRITFC, CUB, Energy Advocates, NWEC have expressed support for this recommendation. CUB notes additionally, the need to thoroughly vet EE investments "in order to provide customers much-needed relief from inevitable rate increases due to costs of investments in CEP compliance and wildfire mitigation, to name a few."[19]

In response, PGE expressed that since Staff will be proposing interim methodology guidance for the workbook template in Docket No. UM 1893 (to be used for the March 1, 2024 filing) and updating the methodology for future cycles, it will no longer be necessary for PGE to elaborate on alternative avoided cost methods within LC 80. PGE expects to collaboratively engage in the UM 1893 process and is currently waiting for follow up from Staff regarding proposed interim changes. Staff is comfortable with PGE providing a proposal in Docket No. UM 1893 and looks forward to the Company's response in its comments on this Staff Report.

Staff Recommendation 4. Direct PGE to work with Staff to propose a new method for calculating avoided costs in Docket No. UM 1893. The avoided cost proposal should resolve the shortcomings identified by PGE and Staff, including but not limited to the shift from one avoided capacity value to annual values, the impact of constraints observed in the model, and the need to procure clean electricity not captured by forward market prices.

[19] LC 80 – CUB's Comments on Staff's Round 2 Comments and Recommendations, p.3.

Cost Containment
Section 10 of HB 2021 lays out a process for a proceeding in which the Commission may identify costs that contribute to compliance with HB 2021 and determine whether the rate impact of HB 2021 compliance has exceeded six percent of revenue requirement so as to provide a narrowly tailored, limited-duration exemption from compliance.[20] AWEC raises this provision and recommends that the Commission condition acknowledgement of PGE's plan on its ability to provide reliable cost estimates in the light of the cost cap provision.

While review of an electric company's CEP is not a proceeding under Section 10, Staff agrees that cost containment is an important aspect of planning and implementing HB 2021 that has not been explored in detail. Discussion in this first IRP/CEP focused on more fundamental questions of whether and how the Company could outline a credible path to compliance under current planning conditions. However, Staff believes that the topics explored in this IRP/CEP review adequately lay the groundwork for cost containment in near-term actions, like any IRP process. Further, the decarbonization planning insights offer more clarity for consideration of expected longer-term cost drivers and risks. Staff considers this a major accomplishment for the initial post-HB 2021 planning process and believes that it would be premature to recommend that the Commission condition acknowledgement on further cost analysis in the near-term. To do so would require PGE to make too many assertions about the cost categories and other methods that may or may not be used to make a determination under ORS 469A.445 in advance of a Section 10 proceeding or any separate Commission direction.

Small Scale Renewable Resources
PGE is required to meet 10 percent of its aggregate electrical capacity with small-scale renewable energy resources (SSRs) by 2030.[21] Staff expressed concerns about the level of detail regarding PGE's SSR compliance position and actions needed to ensure that the Company could meet the standard. Upon request, PGE roughly identified a 400 MW SSR shortfall but did not prioritize a discussion with Staff about its strategy to fill this shortfall.[22] Since its initial IRP/CEP filing, the Company also indicated that it may be beneficial to consider regulatory changes that would ensure net metering can be used to comply with SSR standard.[23]

[20] ORS 469A.445.
[21] ORS 469A.210.
[22] PGE Response to Staff IR No. 197.
[23] See PGE 2023 IRP/CEP, p. 16, which states, "For example, this may require changes to the regulatory framework including net-energy metering and inclusion of net energy metering as a resource needed to accelerate small scale renewable adoption."

Given the limited time to understand and address compliance shortfalls, Staff developed a draft recommendation to direct PGE to conduct an SSR compliance analysis for submission with its next IRP Update. Staff requested that the analysis include data that would help the Commission consider the trade-offs of regulatory changes to ensure net metering resources could be included. Staff also suggested that the Company include any relevant detail about how those regulatory changes may occur.
Energy Advocates express support for Staff's recommendation and notes the importance of Staff's recommendation in the light of PGE's stakeholder discussions about proposed changes to its current net metering policy, which could potentially decrease the amount of customer-sited solar on its system by 2030.

PGE agrees that the next IRP should include SSR analysis in a more explicit way but questions the requested content of the analysis. PGE correctly notes that more clarity about the role of net metering in SSR compliance will be available by that time.

Staff remains frustrated by the Company's lack of simple, clear information about its SSR compliance position and the steps that it plans to take to fill any compliance gaps. Staff understands that the Company may need to conduct more sophisticated IRP analysis to provide the requested information, but is confused why the Company would consider Staff's request for relevant resource planning information out of scope, unhelpful, or duplicative of the backward-looking compliance verification processes outlined in the OAR 860-091-0040.[24] Staff is also unsure why the Company cannot commit to provide better information in its IRP Update, even if it is not based on the complete analysis it plans to provide in the next IRP/CEP.

That said, Staff believes that the discussion about net metering resources' role in PGE's resource future (and PacifiCorp's) has evolved since Staff developed its draft recommendation. The role of net metering in SSR compliance will likely be broached at a policy level before PGE's IRP/CEP Update. Therefore, Staff has removed these pieces from its recommendation. Staff still seeks simple, clear information about PGE's SSR compliance position and the actions that it will take to fill any potential gaps. Staff has revised its recommendation.

<u>*Staff Recommendation 5. Direct PGE in the next IRP/CEP Update to include an SSR compliance analysis. The SSR analysis should state the projected SSR compliance position, broken out by relevant resource types, and outline the actions the Company plans to take to fill any identified SSR shortfalls.*</u>

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[24] Staff assumes that the backward-looking compliance verification process in OAR 860-091-0040 is the portion of Commission Order No. 21-464 that PGE refers to in its Round 2 comments.

Community Engagement
Staff and stakeholders appreciate PGE's continued efforts to engage with various community groups within this planning process and other related processes, for instance, PGE's Distribution System Plan. The Company is taking bold steps into uncharted territory for utility planning. Because PGE is at the beginning of the journey, PGE should be commended for its efforts and reminded that participants will be grappling with these issues together for a long time to ensure an appropriate planning approach is developed.

Staff and stakeholder comments focused on meaningful inclusion of community feedback in PGE's IRP/CEP and transparent communication regarding impacts of such feedback on its plan. Staff's recommendation regarding community engagement prioritizes the creation of a collaborative venue to address these concerns and expects PGE to create opportunities for effective community engagement in future and codevelop metrics or actions that appropriately capture different impacts on and, benefits to communities. PGE expresses support for this effort.

CRITFC provides additional remarks on the significance of engagement and partnership with tribal communities. They point out the importance of recognizing the sovereignty of tribal governments and their authority to govern activities occurring within the reservation boundaries. They express that consideration of diverse interests of tribal communities, and open and transparent communication is key to a successful tribal - utility interaction. Staff agrees that these are elements of a successful partnership between tribal communities and utilities and expects PGE to incorporate these principles in its ongoing and future collaboration with tribal communities. Staff expects this topic to be included in working group discussions.

> *Staff Recommendation 6. Direct PGE to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PGE cannot complete this effort by this timeline, PGE should provide a detailed status update by the same date and explain how it will ensure that remaining issues are resolved as soon as practicable.*

Community Benefits
PGE made a sincere first attempt to develop Community Benefit Indicators and utilize them meaningfully in its IRP/CEP. Staff and several stakeholders, including CUB, Energy Advocates, NewSun, and RNW, have identified opportunity to improve CBIs so that they include clear information on health, environmental, economic, reliability and resilience impacts and/or benefits of PGE's plan on communities. The need to prioritize

and develop meaningful CBIs that capture different impacts and benefits resonate in the comments by almost every participant in this docket.

CRITFC recommends that PGE develop "tribal-specific portfolio CBIs that account for the co-benefits of efficiency and the effect of projects on treaty resources and healthy fisheries". Staff appreciates and agrees that accounting for these community benefits should be a priority in utility planning of a clean energy future.
Staff recommended the Commission adopt a timeline on the development of improved CBIs for the next IRP/CEP. This will retain momentum and prioritization for this important modeling improvement.

Energy Advocates recommend adding a new sentence to this recommendation: "The Commission direct PGE to specify how each of its action plan items advances progress on identified CBIs". Staff believes it is a priority to better tie portfolio analysis and the resulting resource strategy to CBIs. Because the number and content of future CBIs is unknown, Staff wishes to take this matter up after the CBIs have been identified. In considering this requirement, Staff will weigh the relevance of this information and the time it will take to develop and evaluate it.

PGE supports Staff's recommendation and adds that, "PGE's approach to CBIs will aim to articulate how community benefits vary between portfolios, what community benefits are associated with PGE's Action Plan, and how RFP design and scoring can encourage additional and more specific benefits." Staff appreciates this commitment and looks forward to engaging in the CBI development effort. Staff notes that it's expectations for CBIs in Attachment 2 are designed to document discussions that occurred in the IRP/CEP review process. The Company should expect Staff to bring these perspectives to conversations next year for exploration but should not consider them directives or expectations for the outcome of the process.

> *Staff Recommendation 7. Direct PGE to conclude its process to develop informational and portfolio CBIs and provide baseline metrics prior to filing its next IRP/CEP Update. If PGE cannot complete this effort by this timeline, PGE should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.*

Federal Incentives
Federal incentives resulting from the passage of the Infrastructure Investment and Jobs Act (IIJA), passed in 2021 and the Inflation Reduction Act (IRA) passed in 2022 will have important implications for both supply side generation and transmission resources and demand side programs, and adoption of distributed energy resources. PGE has partially accounted for these incentives in the current plan but has indicated that future

plans will include a more robust analysis of federal, state and local incentives and funding options.

Staff's recommendation reflects CUB's recommendation in its Opening Comments that PGE provide timely updates about its analyses and strategies to utilizing available federal funds and how they plan to ensure that 40 percent of benefits flow to disadvantaged communities (resulting from the Justice40 initiative of the Federal government).

CUB, Energy Advocates and PGE have expressed support for Staff's Recommendation.

> *Staff Recommendation 8. Direct PGE to include a report on federal incentive implementation and its key impacts on the Company's Action Plan and 2030 resource strategy with its next IRP/CEP Update.*

QF Assumptions

The Renewable Energy Coalition (REC) raised an issue in its Round 1 comments that Staff unfortunately failed to respond to in its Round 2 comments. Staff regrets this oversight. In comments REC recommended 1) not acknowledging PGE's 2023 IRP assumptions regarding existing QFs and Schedule 202 QFs; and 2) directing PGE to assume that a reasonable number of QFs will renew or otherwise enter new contracts with PGE at the end of their current contracts (such as 100%), and that fewer than all Schedule 202 QFs will develop (such as 50%). In REC's Round 2 comments, they provide a summary of Staff and Commission statements on this issue in previous dockets and utility IRPs and request that Staff draft a:

> [P]ainstakingly clear recommendation for PGE, similar to those already issued for Idaho Power and PacifiCorp, that directs PGE to assume that a reasonable, non-zero number of QFs will renew or otherwise enter new contracts with PGE at the end of their current contracts (such as 100% or nearly 100%), and that a reasonable and realistic number of Schedule 202 QFs will develop (fewer than 100% but more than 0%, such as 50%).[25]

Staff first notes that Commission guidance on this issue will be adopted in UM 2000 prior to PGE's next IRP/CEP.[26] As evidenced by REC's Round 2 comments, this issue has come up repeatedly in IRPs with implications for load/resource planning but also capacity valuation for QF avoided cost prices. Staff believes that a dedicated investigation into this issue alongside other PURPA issues which may be interrelated will result in the best-informed recommendation for long-term use. However, Staff

[25] REC's Round 2 Comments, p. 6.
[26] See Docket No. UM 2000, Staff's scoping proposal, February 24, 2023.

believes that the Company has not acted consistently with previous Commission orders requiring a utility to utilize a reasonable forecast for QF related planning assumptions. In particular, Staff notes the language in Commission Order No. 21-184 which states that modeling renewals of wind QFs in Idaho Power's IRP should include some percentage, "rather than taking an all or nothing approach." Staff understands and appreciates the difficulty faced by PGE in identifying a reasonable renewal rate due to lack of historical data and the uniqueness of the different utilities in the state.

However, Staff reiterates that an all or nothing forecast virtually guarantees an overestimation or an underestimation. Because PGE has not provided a workable alternative Staff supports REC's recommendation for use as an interim approach in PGE's post-IRP avoided cost update. For renewables, Staff recommends that PGE utilize an approach similar to PacifiCorp's approach and assume a 75 percent renewal rate, which has been vetted and approved in other venues. Although this number is based on a different utility's data, it provides a reasonable approach based on empirical evidence with an equal likelihood of under and overestimating the actual renewal rate, resulting in more accurate avoided cost pricing.

For QF success rates, REC has shown through historical data that PGE's Schedule 202 success rate assumption is too high.[27] However, the data is somewhat sparse and difficult to rely directly on without further consideration: there have been only a limited number of contracts executed, only 4 projects were planned and two of them terminated, however the two projects were being developed by the same entity. Staff agrees with PGE that Schedule 202 projects will generally have a higher success rate than smaller Schedule 201 projects. Given that parties generally feel comfortable with a 50 percent success rate for Schedule 201, Staff recommends the use of a 75 percent success rate for Schedule 202 projects. This interim estimate provides a middle ground between the limited data that is available, is more reasonable than the current estimate, and is supported by the proxy Schedule 201 value. It will further provide a more reasonable estimate for avoided cost pricing while Staff and parties review the issue in UM 2000.

NewSun also points out that PGE did not provide draft avoided cost information with its IRP as required by OAR 860-029-0080(3). PGE and NewSun hold different interpretations of what is considered draft avoided cost information. At this point in the investigation, Staff believes that focusing on direction for the final avoided cost information filed 30 days after IRP acknowledgment is most practical. Staff understands NewSun's concerns and believes it may be necessary to reexamine the appropriate relationship between IRP review dockets and review of PURPA avoided cost inputs after changes to avoided cost methods are evaluated in Docket No. UM 2000.

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[27] REC Round 1 Comments, p. 6-8.

<u>Staff Recommendation 9. The Commission should decline to acknowledge PGE's avoided cost pricing inputs and direct PGE to recalculate its IRP inputs using an assumption of 75 percent for QF renewals and the QF success rate for Schedule 202 projects.</u>

<u>Conclusion</u>

PGE's first CEP and 2023 IRP demonstrates an innovative approach to resource planning and exposes the challenges associated with such planning in reaching the fast-approaching emissions reduction goals set by HB 2021. Staff appreciates that, despite the challenges, the Company has made substantial progress in the right direction towards meeting these goals. Staff reiterates the importance of the role of participants who, despite having limited resources, engaged in this process and provided a thorough review of PGE's plans and offered invaluable insights. Staff is truly grateful for that. Staff believes that PGE has made a good start and is confident that continuing the collaborative effort as observed in this process will only lead to better outcomes for the Company's planning in the future.

PROPOSED COMMISSION MOTION:

Acknowledge Portland General Electric's (PGE or Company) 2023 Integrated Resource Plan (IRP) subject to the conditions set forth in Attachment 1, decline to acknowledge the Clean Energy Plan (CEP) and direct the Company to revise and resubmit certain elements of the CEP by the next IRP Update, and direct the Company to take additional actions as provided in Attachment 1.

LC 80

ATTACHMENT 1. SUMMARY OF STAFF'S RECOMMENDATIONS

IRP Acknowledgement:

Staff recommends acknowledgement of the IRP **subject to the conditions** identified below.

Staff Recommendation 1. Acknowledge PGE's CBRE Action Item subject to the condition that PGE pursue the broader range of procurement actions that it identified in comments in this docket.

Staff Recommendation 2. Acknowledge PGE's Energy and Capacity Action Items subject to the following condition: Before issuing its next utility-scale RFP, PGE will file a proposal for a Long Lead Time Resource RFI developed via a stakeholder process in LC 80 and facilitate a stakeholder discussion (workshop) on the findings of the RFI and allow sufficient time for stakeholder review of its RFI before proposing its next steps.

CEP Acknowledgement:

Staff Recommendation 3. Decline to acknowledge PGE's expected reduction of greenhouse gas emissions in the Clean Energy Plan as credible based on the preferred portfolio and direct the Company to make the following revisions and resubmit the revised plan before its IRP/CEP Update in 2025:

- *PGE shall conduct hourly production cost simulation of its preferred portfolio under the Reference Case in a manner that separately tracks hourly purchases and hourly sales. PGE will use this analysis to revise its GHG emissions forecast and to revise its submission to DEQ.*
- *PGE shall update the Preferred Portfolio accordingly and provide a brief narrative explanation of the key planning insights derived from this exercise.*

Other Issues:

Staff Recommendation 4. Direct PGE to work with Staff to propose a new method for calculating avoided costs in Docket No. UM 1893. The avoided cost proposal should resolve the shortcomings identified by PGE and Staff, including but not limited to the shift from one avoided capacity value to annual values, the impact of constraints observed in the model, and the need to procure clean electricity not captured by forward market prices.

Staff Recommendation 5. Direct PGE in the next IRP/CEP Update to include an SSR compliance assessment. The SSR analysis should state the projected SSR compliance

position, broken out by relevant resource types, and outline the actions the Company plans to take to fill any identified SSR shortfalls.
Staff Recommendation 6. Direct PGE to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PGE cannot complete this effort by this timeline, PGE should provide a detailed status update by the same date and explain how it will ensure that remaining issues are resolved as soon as practicable.

Staff Recommendation 7. Direct PGE to conclude its process to develop informational and portfolio CBIs and provide baseline metrics prior to filing its next IRP/CEP Update. If PGE cannot complete this effort by this timeline, PGE should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

Staff Recommendation 8. Direct PGE to include a report on federal incentive implementation and its key impacts on the Company's Action Plan and 2030 resource strategy with its next IRP/CEP Update.

Staff Recommendation 9. The Commission should decline to acknowledge PGE's avoided cost pricing inputs and direct PGE to recalculate its IRP inputs using an assumption of 75 percent for QF renewals and the QF success rate for Schedule 202 projects.

ATTACHMENT 2. STAFF EXPECTATIONS FOR FUTURE IRP

Staff Round 2 comments also highlighted a range of opportunities to improve the next IRP/CEP that PGE should be prepared to address in its plan development process and the investigation into the Commission's planning and procurement policies expected in 2024. This is a list of priorities and ideas that Staff gained through its first experience with IRP/CEP review. Staff believes they are worth documenting at the end of this process for several reasons. First, to recognize the amount of effort that went into running concerns to ground and determining that it is acceptable to address the concerns through improvements in the next IRP. In addition, Staff seeks to promote continuity going into development of the next IRP/CEP and planning and procurement investigation. Staff also believes that this documentation will help PGE understand and consider Staff's ideas as early in the next planning process as possible. Most importantly though, Staff presents its expectations in this manner to avoid the impression that they are comprehensive or rigid requirements for future planning. These are a starting point for future discussions amid rapidly changing conditions. Staff has seen Commission direction for future IRPs go stale but consume significant utility and stakeholder time on implementation. Staff seeks to avoid that here, as well.

If PGE determines that there are negative impacts or insurmountable challenges to moving forward with one of these concepts, Staff looks forward to engaging in further discussion during the next IRP/CEP development process or planning/procurement investigation. It is not necessary to add language to that effect or to note that any of these ideas will be subject to stakeholder input. That said, Staff appreciates the extensive feedback and provides updates and other responses below.

Customer Actions

- Include all EE identified as optimal in the Preferred Portfolio in the Action Plan, regardless of funding source. Ensure that other resource actions are informed by the overall target/optimal EE level.

PGE suggested including the option for "an explanation" in the event the optimal amount of EE is not included in the Preferred Portfolio. Staff finds that this is inherent in the nature of the list of expectations and does not need to be added.

CBRE Actions

- Improve the precision of the CBRE potential analysis, which may include a bottom up, community-driven potential analysis that is validated with AdopDER analysis.
- Articulate a more comprehensive and proactive CBRE acquisition strategy that includes leveraging a wide range of existing and proposed procurement pathways, identifying funding and technical assistance opportunities that can

ensure lower costs and greater benefits, and continual community, Staff, and stakeholder engagement.

- Quantify the costs and benefits of offsetting fossil fuel resources with CBREs with enough precision to support a meaningful discussion of the tradeoffs of CBRE and non-CBRE resource actions.

PGE is willing to meet Staff expectations regarding CBRE analysis but points out the need for the Company to use its resources appropriately to provide specific analytical expectations as expressed in Staff comments.

Energy and Capacity Actions

- If PGE issues another RFP before the Commission concludes an investigation into its planning and procurement policies, Staff expects the Company file a list of all relevant modeling inputs and assumptions that influence capacity and energy need, avoided costs, and project capacity, energy, and/or flexibility valuation. The Company should identify those inputs and assumptions it would anticipate updating prior to issuing future RFPs and those it assumes would only change as part of a new IRP filing or IRP Update.
- Include a proposal for the use of CBIs in scoring the next utility-scale RFP bids.
- Be dynamic with procurement targets and consider how market intelligence from RFPs might inform demand side resource valuation or procurement strategies for resources not participating in bidding opportunities.

PGE suggests minor modification regarding expectations around modeling inputs explaining that there are underlying assumptions in the workings of time series and other modeling techniques that need not be specified. Staff agrees and clarifies that Staff may still want to understand the inputs and assumptions that maybe relevant for Staff and stakeholders' understanding of the modeling techniques.

GHG Modeling

- If PGE cannot adapt its modeling framework to conduct hourly dispatch analysis of the Preferred Portfolio to demonstrate that the Preferred Portfolio can achieve the Company's 2030 GHG target under DEQ accounting rules to achieve all of the requirements of Draft Recommendation 6, Staff still expects PGE to develop this capability at an appropriate and informative timestep for its next IRP/CEP using inputs from Staff and stakeholders.

Staff appreciates the Company's willingness to continue to improve its emissions modeling and expects that PGE will develop an appropriate timestep after considering stakeholder inputs and current best practices. Staff clarifies that it will enter the discussions with an expectation of at least hourly analysis.

Transmission Modeling

- Provide a comprehensive transmission study showing the options PGE has explored, including the use of on-system resources, for instance DERs and CBREs, existing and new regional and inter-regional transmission systems, and others, in determining the transmission projects that can be realistically and feasibly selected to meet 2030 emissions targets. Staff expects that a more rigorous analysis of transmission needs will use power flow models.
- Provide a more detailed analysis of PGE's transmission product assumptions including an analysis to reconcile its transmission assumptions with those required in WRAP that better quantifies curtailment risk.
- Better explain how proxy transmission capacity levels align with the Company's peak needs and overall resource strategy.

PGE agrees that there is a need for more comprehensive benefit cost analysis related to transmission options and commits to provide that information before the next IRP Update. Staff appreciates PGE's commitment to provide a comprehensive transmission analysis and is open to reviewing the Company's explanation for why a power flow analysis was not appropriate in establishing transmission needs.

Portfolio Analysis

- Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios beyond the inclusion of CBREs i.e., allow comparison of the CBIs of the entire portfolio of actions and allowing GHG emissions to vary across portfolios.
- PGE must address the additional requirements in HB 2021, namely GHG emissions and community impacts, by either integrating emissions and community impacts with the cost benefit measures or by using separate measures for emissions and community impacts in its portfolio scoring.

PGE understands the need for a comprehensive understanding of potential tradeoffs in resource options, but believes the example stated by Staff is overly prescriptive in terms of how that tradeoff analysis should be provided. However, in the light of HB 2021, Staff and stakeholders need to develop a better understanding of tradeoffs in terms of GHG emissions and community impacts and benefits of different resource actions. Therefore, Staff believes that the above expectation is reflective of Staff and stakeholders' perceptions of capturing specific tradeoffs among portfolios in addition to cost and risk. This does not preclude alternative methods that PGE may use to produce the outcome that sheds light on these specific tradeoffs.

Reliability Analysis

- Evolve the RA planning standard in a manner consistent with a 1 in 10 years standard or otherwise identified in the investigation into planning and procurement policies in 2024.
- Incorporate estimated benefits associated with participating in a regional RA program.
- Incorporate estimated benefits associated with participating in a regional market.
- Consider resource adequacy portfolio effects in designing and evaluating portfolios. At a minimum, Staff expects PGE to test the annual RA performance of their draft and final portfolios, to be transparent with Staff and stakeholders in the event that these tests identify material issues with the assumptions in PGE's portfolio optimization model, and to explore alternatives or improvements if needed.

Staff provides this revised set of expectations based on PGE's response to Staff's Round 2 comments on reliability modeling expectations as well as stakeholder inputs on this issue.

Small-Scale Renewable Energy

- Include quantitative SSR compliance analysis that specifies the Company's compliance position and actions that it plans to take to acquire the needed resources.
- Include cost information that support the Company's strategy to meet the SSR requirements in a manner that controls costs and drives benefits to communities.

Community Engagement

- Provide detailed documentation of community, stakeholder, and CBIAG input received in the development of the IRP/CEP and clearly explain whether and how the input was used to inform the Company's plan.
- Present the CEP in a manner that is accessible, clear, and transparent. There should be evidence of proactive measures taken to integrate community feedback into iterations of CEP analysis and subsequent actions. A methodical approach to demonstrating the influence of community input on the resource actions and strategies outlined in the CEP is needed to validate the evidence of environmental justice principles in the planning process.

Community Benefits

- Staff is supportive of the Company's proposal to hold a process to further develop pCBIs with the help of a third party.
- Staff also plans to consider minimum expectations for CBI development and use in portfolio modeling in the Commission's re-examination of planning and procurement policies in 2024.
- Among other things, Staff will look for PGE to:
    - More precisely capture pCBIs and iCBIs with improved methods.
    - Expand pCBI beyond CBREs in portfolio analysis, including recognizing the tradeoffs of varying levels of different resource types and locations. Staff would expect this to show that CBIs levels are different in portfolios with more EE for example.
    - Consider the impact of thermal and hydro systems on EJ communities.
    - As the Company works to refine its CBIs and CBRE analysis in the future, Staff believes that it will be a priority to work toward a modeling approach that will be reflective of trackable CBI benefits and allows comparison of CBRE and non-CBRE actions.
    - Better inform CBIs and methods with input from stakeholders and community.
    - Enhance tribal-focused CBIs.
    - Use CBIs to better reflect the health impacts of EE.

- Enhance the ability of CBIs to better reflect the resiliency benefits of actions—CBRE and not CBRE.

PGE expresses commitment to developing CBIs with meaningful input from stakeholders and communities but objects to the level of specificity provided in Staff expectations regarding specifics of CBI development and suggests omission of the above list that could potentially capture community benefit or impacts from different utility actions. Staff provided the above list based on Staff and stakeholders' analysis of the current CBIs and related analysis in the IRP/CEP. This list reflects stakeholders' inputs and is relevant documentation of the opinions expressed in this docket. These are a starting point and should not be considered rigid requirements for the outcome of PGE's CBI improvement process.

Federal Incentives

- The Company should take ownership over the successful implementation of federal incentives and provide updates about the impact on its current strategy as information becomes available.

RECs

- Staff is committed to working with the Company to identify the appropriate REC analysis for future IRP/CEPs in the Commission's investigation into planning and procurement policies and/or development of PGE's next IRP/CEP.

- Staff does not plan to discuss REC disclosure, communications, and transparency policies until after the Commission order in Phase 1 of UM 2273 is issued.