# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

| | |
|---|---|
| In the Matter of<br><br>PORTLAND GENERAL ELECTRIC COMPANY,<br><br>Investigation into Marginal Cost Study<br><br>Treatment Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I. | Docket No. UM 2377 |

## Portland General Electric Company's Opening Brief

February 4, 2026

## Table of Contents

**<u>Table of Authorities</u>**

**Cases**



**Statutes**

**Public Utility Commission of Oregon Orders**

# I. Introduction

Portland General Electric Company (PGE) is committed to serving customers with safe, reliable, affordable and increasingly clean energy. Our goal in this proposal is to serve all customers, including new data center and large load customers, in a manner that will ensure data centers pay their share of the costs associated with growth.[1] If PGE's complete proposal is adopted, in the first year, data centers will see an estimated 26% rate increase and residential customers will see an approximately 2% rate decrease. This outcome reflects a deliberate rebalancing of costs towards customers that are driving the growth. This balanced proposal will ensure just and reasonable rates consistent with longstanding Oregon cost causation and cost-of-service principles. PGE's proposal is aligned with the intent of the POWER Act (HB 3546) and meets all of its requirements by ensuring that large load data centers pay the full cost to serve them and other customers are protected from any unwarranted cost shifting.

The emergence of data center and rapid large load growth poses a number of risks, challenges and opportunities for Oregon. And in the face of this unprecedented load growth and intensifying national and regional reliability concerns, the Oregon Public Utility Commission's (Commission) role in ensuring cost causation and customer protections has never been more critical. This docket presents an opportunity for PGE and the Commission to adopt policies that allow PGE to serve data centers and large loads while affirmatively protecting residential and small business customers from bearing disproportionate costs or risks. PGE's proposal would also allow our existing residential and other customer classes to benefit from the presence of data centers and large loads on the system through their contributions toward necessary infrastructure improvements and the creation of economies of scale through an expanded customer base.

[1] PGE/100, Ferchland-Barrow/1.

PGE's proposal provides the best, durable path to mitigate risks associated with data centers and large loads – whether concerning access to renewable resources, carbon emissions goals, or service costs. Like many utilities across the country, PGE is projecting large-scale load growth over the next several years from data centers, digital service providers and semiconductor manufacturing and supply chain investments. Absent an updated cost-causation based framework, this growth would place upward pressure on rates for existing customers and increase system risk.

If PGE does not serve this growth, there is a greater risk that PGE's residential, small business and industrial customers will lose access to the best renewable resources due to increased market competition from data centers or large load customers seeking access to these same resources from different service providers. Data centers and large load customers are already present in Oregon and actively contracting for the same generation resources that PGE needs to serve our existing customers reliably with renewable resources. Recent experience shows that shortlisted projects have withdrawn from RFPs after receiving offers from unregulated entities.[2] PGE's existing customers are put at risk if data center and large load customers are served by other providers who will then compete against PGE and our customers for the same scarce affordable renewable resources.

Further, PGE's grid infrastructure is aging, and adding new data center and large load customers would directly support existing customers by spreading the costs of these necessary infrastructure improvements, especially if it is done as our proposal recommends, which includes allocating the full costs of growth to the customer classes causing the growth. Finally, pushing data centers and large load growth away from PGE will lead them to providers without

[2] PGE/200, Ferchland-Barrow/33-34.

equivalent emissions reduction obligations or regulatory oversight, which is inconsistent with Oregon's clean energy goals and will not benefit our existing customers.

PGE's proposal incorporates enforceable protections to guard against stranded assets, ensure capital discipline before extending infrastructure to new loads, and allocate costs based squarely on cost causation without unnecessary complexity or administrative burden. The risks associated with data center growth are best managed by serving these customers within a Commission-regulated framework that assigns them the full cost of service—rather than adopting requirements that would push this load outside the regulated system and increase risk to remaining customers.

To better understand how PGE's proposal strikes the right balance, it helps to examine the data underlying system peak growth. PGE is receiving an increasing number of large load requests, consistent with national trends. Demand growth from larger customers has outpaced that of residential customers and is anticipated to significantly accelerate within PGE's service territory—even as residential electrification continues at a more gradual pace. [3] Over the past three years, the residential class accounted for 45% of the growth in system peak during the four highest months while showing only modest growth in relative terms based on contribution to peak demand.[4] Customers eligible for the proposed data center class, which currently represent just 4% of the system peak during the four highest use months, have grown five-fold since 2022 and contributed 54% to total system peak growth during the same period.[5] By 2033, PGE anticipates that the growing data center class will be responsible for 20% of peak usage.

---

[3] *PGE Investigation into New Load Connection Costs*, Dkt. UE 430, PGE/200, McFarland-Macfarlane/1, 6 (December 20, 2024) .

[4] PGE/100, Ferchland-Barrow/25. After adopting Citizens' Utility Board's proposed methodological approach to account for class contribution to energy efficiency discussed *infra* in Section III,10, the residential contribution decreased to 28%. PGE/400, Ferchland-Barrow-Jose/13.

[5] PGE/400, Ferchland-Barrow-Jose/16.

Together, these two classes (Schedules 7 and 96) have been the primary drivers of the recent system peak growth.

A cost allocation framework that relies solely on forecasted peak contributions would improperly assign a disproportionate share of incremental costs to residential customers and materially under-assign costs to Schedule 96. At the opposite extreme, allocating all new costs exclusively to Schedule 96 would also be inconsistent with cost causation, as data centers are not the sole contributors to peak growth. By allocating new costs based on class contribution to system peak growth, PGE's proposal produces an equitable, principled and evidence-based cost allocation outcome.

Before submitting this proposal, PGE undertook a thorough process to reevaluate existing cost allocation methodologies to make sure that data centers and large load customers were paying the full cost required to serve them. Throughout this docket, PGE has iteratively reviewed and refined its proposals in response to stakeholder input to develop a framework that is logical, administrable, and aligned with the directives of HB 3546 (June 19, 2025).[6] The resulting proposal reflects a durable, transparent, and equitable structure that fairly allocates growth-related costs to the customers driving that growth so that each customer class pays for the costs it causes and the system benefits it receives.[7] If the Commission approves the proposal, PGE will be able to add a growth-pays-for-growth component to its current cost allocation methodology, applied consistently across customer classes, and position the Commission to manage continued load growth over the long term.[8]

[6] PGE/400, Ferchland-Barrow-Jose/16, 48.
[7] PGE/400, Ferchland-Barrow-Jose/1-2.
[8] PGE/400, Ferchland-Barrow-Jose/2.

Specifically, PGE requests that the Commission approve a dedicated Data Center rate class (Schedule 96)[9], changes to marginal cost allocation methodologies to ensure customers responsible for growth pay for that growth, updates to Rule I to increase transparency, opportunities for special contracts to enable tailored but fully regulated service options for customers, and targeted enhancements to Contributions in Aid of Construction (CIAC) policies. PGE is not requesting a revenue change in this docket. Instead, PGE's complete proposal reallocates costs so that data centers bear a greater share of system growth costs, while residential customers see reduced cost responsibility. At every stage, the trajectory of these changes has moved in favor of residential affordability and risk protection.

Central to the proposal is the Peak Growth Modifier (PGM). The PGM is a new cost allocation method that assigns growth-related costs to customer classes based on their contribution to system peak load growth. If adopted, it will require data centers and large load customers to bear a substantially higher share of near-term costs as their contribution to system peak increases, thereby preventing those costs from being shifted to customers who did not cause them.

PGE's proposal was independently analyzed by London Economics International, which found that PGE's proposed data center class design, including minimum demand charges, exit fees, and exceedance penalties—provides stronger protections for other customers than those adopted in other jurisdictions with a significant volume of data center activity.[10] This external validation confirms that PGE's proposal is not only reasonable, but comparatively conservative in protecting existing customers.

[9] Schedule 96 would be a specific new customer rate schedule that is dedicated to the data center class, which is necessary to implement the appropriate allocation of the cost of serving these customers and address concerns about undue and unreasonable cost shifting. PGE/400, Ferchland-Barrow-Jose/3.
[10] PGE/300, Fagan-Frayer/27.

Oregon has affirmatively encouraged data center and advanced manufacturing development through tax policy, land-use decisions, and local economic development incentives, and these customers are already locating in and operating within PGE's service territory. As the electric service provider of last resort, PGE has a legal obligation to serve this load when it interconnects to the system. With approval of PGE's proposal, the Commission will support growth in Oregon with balanced protections and requirements that incentivize data centers and large load customers to seek cost-of-service or special contract avenues to join PGE's system and select into the Commission's rigorous, facilitated, and transparent process that ensures regulatory oversight and support towards State clean energy goals and policies.

This brief is organized in the following fashion: (1) background, containing historical and procedural history for this docket, including the development of the contested issues list; (2) the standard of review; (3) key issues at the hearing, (4) argument, addressing each of the contested issues. We have also included a key issues reference chart (Appendix A), which summarizes PGE's positions on the contested issues and provides page references to the relevant sections of the brief.

The record is clear: the Commission's approval of PGE's proposal will ensure that residential and other non-large-load customers do not bear the higher costs and risks associated with data center-driven growth, while positioning the Commission to manage future load growth in a manner that is fair, lawful and consistent with the public interest.

## II. Background

During PGE's 2024 general rate case, the Commission directed the opening of a docket to investigate new load connection costs and consideration of an interim measure to mitigate potential risks to customers associated with new large loads during the pendency of the investigation.[11] [12] The resulting docket, UE 430, was opened in December 2023.[13]

On December 20, 2024, PGE submitted its initial proposal in UE 430. In response to feedback from parties and direction from the Commission, PGE made a revised filing on February 21, 2025. PGE's filing proposed changes to Rule C and Rule I and a modified tariff.[14] The Commission approved PGE's revised UE 430 filing, which made any customer contracts signed under the revised Rule C and I subject to change based on the outcome in this docket. Adopting Staff's recommendation in UE 430, the Commission then directed the opening of this instant docket, ordering the Administrative Hearings Division to investigate, non-exclusively, further modifications to Rule C and Rule I and PGE's marginal cost study's treatment of transmission costs for large customers.[15] This docket, UM 2377, was opened on March 7, 2025.[16]

On June 16, 2025, Governor Tina Kotek signed HB 3546, also referred to as the POWER Act, into law.[17] The law states that, among other things, the Commission shall provide for separate and distinct classification of service for a large energy use facility as defined within the Act.[18]

---

[11] *PGE Request for a General Rate Revision; and 2024 Annual Power Cost Update;* Dkt. UE 416, Order No. 23-386 (October 30, 2023) (First, Second, Third, Fourth, and Sixth Partial Stipulations Adopted; Request for General Rate Revision Approved as Revised).

[12] PGE's 2025 general rate case resulted in PGE's current general rates and revenues requirements. *PGE Request for a General Rate Revision*, Dkt. UE 435, Order No. 24-454 (December 20, 2024). During this rate case, PGE had two separate customer classes within its tariff that allocate cost-of-service to larger, nonresidential customers (Schedules 89 and 90). In addition, it had three customer classes for nonresidential customers that are below 4,000 kW.

[13] *PGE Investigation into New Load Connection Costs*, Dkt, UE 430, Memorandum Opening Docket and Notice of Scheduling of Status Conference (December 1, 2023).

[14] Dkt. UE 430, Order No. 25-091 (March 6, 2025).

[15] *Id.*

[16] Opened at the March 7, 2025 Public Meeting, Initial Application (Mar. 11, 2025).

[17] HB 3546, 83rd Leg., Reg. Sess. (Or. 2025), effective June 16, 2025.

[18] ORS § 757.292 (2).

PGE introduced its new, proposed data center rate class, referred to as Schedule 96, for customers engaging or who will engage in data center business with a demand of 20 megawatts (MW) or greater during opening testimony in this instant docket on August 11, 2025. [19]

This docket has ten total parties and has included three rounds of simultaneous testimony (opening, rebuttal, and surrebuttal), along with a hearing that occurred on January 21, 2026.[20] As of February 3, 2026, more than 1,600 public comments have been received by the Commission about issues in this docket.[21]

The first large cost of service data center was seen in PGE's service territory in 2022.[22] During opening testimony, PGE identified five customers accounting for sixteen total service points that would be the initial customers within the proposed Schedule 96 and its direct access equivalents consistent with the 2025 test year; a total of nine service points would be moved from Schedules 89 and 90 into Schedule 96.[23]

Early in the UM 2377 docket, after consultation and feedback from parties, Staff proposed and circulated a draft issues list.[24] Parties were given the opportunity to file written comments on the issues list. On May 20, 2025, Administrative Law Judge (ALJ) Mapes adopted the issues list as filed (Ruling).[25] On January 7, 2026, PGE circulated an expanded issues list to Parties.[26] On January 14, 2026, PGE filed the resulting contested issues list with a total of fifty-

---

[19] PGE/100, Ferchland-Barrow/3.

[20] Notice of Hearing (Jan. 9, 2026). *See* Service List, showing Alliance of Western Energy Consumers [AWEC], Amazon Data Services, Climate Solutions Et. Al. [the Coalition], the Columbia River Inter-Tribal Fish Commission [CRITFC], Data Center Coalition [DCC], Northwest & Intermountain Power Producers Coalition [NIPPC], Oregon Citizen's Utility Board [CUB], PGE, Staff, and Verrus LLC [Verrus].

[21] Oregon Public Utility Commission*, Dkt. UM 2377*, *Public Comments*, available at https://apps.puc.state.or.us/docketpubliccommentreport?DocketID=24470.

[22] PGE/400, Ferchland-Barrow-Jose/17. PGE's service territory included much smaller data centers prior to 2022.

[23] PGE/100, Ferchland-Barrow/11.

[24] Staff Proposed Issues List (April 17, 2025).

[25] Ruling (May 20, 2025).

[26] PGE's Contested Issues List (January 14, 2025).

six specific issues.[27] The issues set forth in the Ruling were reflected and generally expanded upon in PGE's contested issues list, with one exception.[28] One of the issues identified in the Ruling was "Changes to PGE Rule C and Rule I".[29] PGE had previously proposed modification to Rule C in UE 430, including revising it to incorporate a provision that mitigates the potential for customers to artificially increase their load or demand to meet contractual minimum demand obligations by use of tools like load banks.[30] The Commission suspended the advice filing incorporating the changes, permitting the later filing of a revised tariff.[31] The proposed revisions to Rule C were incorporated into the revised tariff and became effective for service on or after April 16, 2025.[32] Neither PGE nor any of the parties propose further changes to Rule C at this time.[33]

## III. Standard of Review

As the filing utility seeking to establish a new rate or rate schedule, PGE bears the burden of showing that the rate or rate schedule proposed is fair, just, and reasonable for all customer classes, including customers in the newly created data center schedule, and that it complies with the requirements of the POWER Act, HB 3546.[34] PGE's burden of proof has two aspects, both

[27] *Id.*
[28] Ruling (May 20, 2025), and PGE's Contested Issues List.
[29] Ruling (May 20, 2025).
[30] Dkt. UE 430, PGE/200, McFarland-Macfarlane/30 (December 20, 2024).
[31] Dkt. UE 430, Order No. 25-091 (March 6, 2025).
[32] *Portland General Electric Company's Rule C Conditions Governing Customer Attachment to Facilities* (effective on or after January 1, 2024), available at https://assets.ctfassets.net/416ywc1laqmd/5SfZZl4LC1xf9xctCK3Aqr/e113df2171861d6f2de9672feeabca24/Rule_C.pdf.
[33] PGE/100, Ferchland-Barrow/32.
[34] ORS § 757.210(1)(a) and ORS § 757.292; *see also,* Dkt. UE 435, Order No. 24-110 at 2 (April 25, 2024) ("[i]n investigating the rate request, we weigh the evidence submitted by the utility, Staff, and other parties, with the utility bearing the burden of showing that the proposed rates are fair, just and reasonable."

fully satisfied: burden of persuasion and burden of production.[35] [36] PGE's burden of persuasion is our obligation to establish a given proposition in order to succeed.[37] [38] PGE's burden of production requires evidence showing that our proposed rates satisfy the applicable legal requirements.[39]

PGE has exceeded its burden in this case by submitting substantial evidence, including multiple rounds of testimony grounded in facts and data, provided independent expert analysis in writing and expert witness participation in a hearing, and has proven that our proposal will result in fair, just, and reasonable rates and satisfy the POWER Act. Parties have not rebutted the evidence put forward by PGE. Their positions are either not supported by substantial evidence or not required by, or inconsistent with, the general legal requirements of "fair, just, and reasonable rate" and the POWER Act.[40] Indeed, upon review of the totality of evidence, PGE has clearly surpassed the legal standard of a preponderance of the evidence and the Commission should

---

[35] *Idaho Power Company Application for a General Rate Revision*, Dkt. UE 426, Order, No. 24-311 at 3 (September 23, 2024); *see also Northwest Natural Gas Company Request for a General Rate Revision*, Dkt. UG 435, Order 22-388 at 52 (Oct. 24, 2022); *see also*, ORS § 40.105, Rule 305 ("[a] party has the burden of persuasion as to each fact the existence or nonexistence of which the law declares essential to the claim for relief or defense the party is asserting,") *and see*, *Gordon v. Teacher Standards and Practices Com'n*, 265 Or.App.722 at 728, 337 P.3d 133 at (October 1, 2014) (burden of persuasion is the burden of convincing the trier of fact that an alleged fact is true, *citing State v. James*, 339 Or. 476 at 487, 123 P.3d 251 at 257-258 (November 14, 2005), "[t]he burden of persuasion is, in essence, a method of breaking ties regarding disputed factual questions.")

[36] Dkt. UE 416, Order No. 23-386 at 3 (October 30, 2023).

[37] *PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Dkt. UE 115, Order No. 01-777 (August 31, 2001), citing *Hansen v. Oregon-Wash. R. & Nav. Co*., 97 Or. 190 at 210-211, 188 P. 963 at 969 (April 13, 1920); *see also,* Clifford S. Fishman & Anne Toomey McKenna, 1 Jones on Evidence *Burdens of Proof in Civil Cases: General Principles*,§ 3.5 (7th ed. November 2025) ("[t]he "burden of persuasion" is a burden of showing that the preponderance of the evidence supports a particular finding; if the evidence is evenly balanced, the party that bears the burden of persuasion must lose.")

[38] *Revisions to the Administrative Rules regarding Practice and Procedure*, Dkt. AR 235, Order No. 10-400 at D(2)(a) (October 14, 2010).

[39] ORS § 756.040; *see also,* Dkt. UE 426, Order No. 24-311 at 3 ("…Idaho Power must submit evidence showing that its proposed rates are just and reasonable."); *Calpine Energy Solutions LLC v. Public Utility Commission of Oregon,* 298 Or.App. 143 at 159, 445 P.3d 308 at 317 (June 19, 2019) ("PacificCorp 'bore the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is far, just and reasonable.'").

[40] ORS § 183.482(8)(c); *see also*, *Younger v. City of Portland*, 305 Or. 346 at 360, 752 P.2d 262 at 270, (March 29, 1988) ("[s]ubstantial evidence exits to support a finding of fact when the record, viewed as a whole, would permit a reasonable person to make that finding," *citing Universal Camera Corp. v. Labor Bd*., 340 U.S. 474 at 487–88, 71 S.Ct. 456 at 464–465; *City of Portland v. Bureau of Labor and Ind*., 298 Or. 104 at 119, 690 P.2d 475 at 484 (1984).

approve our proposal because it will result in fair, just, and reasonable rates that comply with the POWER Act. [41]

## IV. Key Issues from the Hearing

**Actual power cost and pricing excursions**. PGE's PGM allocates costs for generation, transmission assets, and net variable power costs using a "growth pays for growth" methodology, assigning higher percentages to data centers and large loads based on their growth contribution. Extreme pricing events are not modeled in annual net power cost updates (Schedule 125) but

[41] Dkt. UE 435, Order No. 24-454 at 5 (December 20, 2024); *see also, PacifiCorp, Request for a General Rate Revision,* Dkt. UE 374, Order No. 20-473 at 4 *(*December 18, 2020*)* (failure to meet burden caused by either failure to present adequate information in the first place or by opposing party presenting persuasive evidence in opposition to the proposal), *citing* 298 Or. App. 143; *PacifiCorp*, Dkt. UE 116, Order No. 01-787 at 6 (September 7, 2001) ("The Commission's role is to weigh the evidence presented on each issue in the case and determine where the preponderance lies. [The Commission] make[s] that decision on the record as a whole." (*citing to U.S. West Communications, Inc. Application for an Increase in Revenues*, Dkt. UT 125, Order No. 97-171 at 8 (May 19, 1997); *Riley Hill General Contractor, Inc. v. Tandy Corp*, 303 Or. 390 at 402, 737 P.2d 595 at 602 (May 27, 1987) ("a 'preponderance of the evidence' means that the jury must believe that the facts asserted are more probably true than false."); 298 Or.App. 143 at 6 (June 19, 2019); *see also*, OPUC Internal Operating Guidelines, available at https://apps.puc.state.or.us/orders/2020ords/20-386.pdf, stating that "[t]he [Administrative Procedures Act] requires that final orders in contested cases be based upon the evidentiary record. The evidentiary record consists of testimony received into evidence, a transcript of the hearing, evidence officially noticed, and offers of proof […]" Appx. A at 15; ORS § 183.450, "[…][except] for evidence … offered and made a part of the record in the case, and except for matters stipulated … no other factual information or evidence shall be considered in the determination of the case …" [except through subsection (4) (official notice and hearing)] at 2, 4; *see also* ORS § 756.558(2), "[t]o decide that rates are fair, just and reasonable, the Commission prepares and enters findings of fact and conclusions of law upon the evidence received in the matter and shall make and enter the Commission's order thereon."; ORS § 756.040 ("[r]ates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility, with a return to the equity holder that is: (a) [c]ommensurate with the return on investments in other enterprises having corresponding risks; and (b) [s]ufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital; see also, ORS § 757.211 (2), "[I]n determining whether an electric […] company's proposed residential rate or schedule of rates to be established or increased or changed is fair, just and reasonable, the […] Commission shall balance the interests of the utility investor and the consumer by considering the cumulative economic impact of the proposed rate or schedule of rates on the electric or […] company's residential ratepayers.") *See also*, *Utility Reform Project v. Oregon Public Utility Com'n*, 277 Or.App. 325 at 340, 372 P.3d 517 at 525 (April 6, 2016) ("[t]he governing statutes direct the PUC "to examine three key components in ratemaking"—a utility's operating expenses, adequate revenue for the capital costs of the utility, and the rate of return on the utility's capital investment. In calculating rates, "there is no single correct sum, but rather a range of reasonable rates," *citing Gearhart v. Public Utility Com'n of Oregon*, 356 Or. 216 at 220, 339 P.3d 904 at 906, (October 2, 2014). *And see*, *PGE Request for a General Rate Revision*, Dkt. UE 335, Order No. 19-218 at 2 (April 11, 2019) (Commission evaluates rates based on "the reasonableness of the overall rates" and not necessarily the "theories or methodologies used or individual decisions made," quoting *PacifiCorp Request for a General Rate Revision*, Dkt. No. UE 210, Order No. 10-022, at 6 (Jan 26, 2010), quoting *Application of PGE for an Investigation into Least Cost Plan Plant Retirement*, Dkt. DR 10, et al., Order No. 08-487 at 7-8 (Sept 30, 2008).

would appear in power cost adjustment mechanism dockets (Schedule 126). As testified, PGE expects similar PGM concepts would apply to future PCAM proceedings.[42] Further details appear under issues 14 and 16.

**Access to limited affordable generation resources**. This challenge stems from market forces, federal policies, and increasing data center presence nationally and regionally—not from PGE's proposal. Our approach allows us to serve data centers with full cost allocation, protecting other customers from cost shifts. Our proposal mitigates the risk that data centers will directly or indirectly compete with PGE and our customers of renewable resources. PGE's regulated portfolio prioritizes cost-of-service customers, and Schedule 96 requires Commission approval for special contracts, all ensuring that cost-of-service customers are protected and POWER Act requirements are satisfied.[43] Further details appear under issues 44 through 46.

**Flexible Loads**. PGE's incentive-based approach to flexible loads has achieved nearly 100% participation from data centers in our cluster study process. Under this approach, PGE can accelerate the availability of capacity due to transmission constraints based on data centers offering flexible load options. While we remain open to program adjustments, mandating flexibility would be challenging given the customized nature of current flexibility options for data centers. While parties have suggested creating additional options for certain types of flexible options, the information available is not yet sufficient to determine the viability, much less the advisability, of these options. We welcome continued review and adjustments as we gain experience with these options.[44] Further details appear under issues 3 and 53.

---

[42] Oregon Public Utility Commission, *Special Public Meeting UM 2377 Investigation into Marginal Cost Study Treatment of Costs for Large Customers* at 50:30–52:00 (January 21, 2026). https://oregonpuc.granicus.com/player/clip/1598?view_id=2&redirect=true.
[43] *Id.*
[44] *Id.*

**Access to Capital**. Transmission capacity needed to support load growth is increasingly constrained by supply-chain bottlenecks, land-use limitations, and lengthy permitting processes. As a result, PGE may be unable to deploy capital and build new infrastructure at the pace required to meet the rapidly growing demand from data centers. While our cluster study process does not explicitly mention capital availability checks, we do evaluate our capacity to meet commitments resulting from these studies. PGE has sufficient capital for current cluster study projects without adversely impacting PGE's balance sheet.[45] If future requests can be served within available transmission capacity and exceed PGE's capital capacity, we would allocate capital without undue discrimination. PGE is open to adding language to Rule I documenting our consideration of any capital constraint in the cluster study process.

PGE's capital needs are also mitigated under our proposal through the targeted use of contributions in aid of construction (CIAC) for distribution assets and the availability of special contracts as permitted under the POWER Act. Further details appear under issues 44 through 47.

## V. Arguments

PGE addresses each of the issues identified in the contested issues list when presenting its arguments below. PGE respectfully requests that the Commission find for PGE on each of the contested issues pertaining to docket scope, which include but are not limited to, approval of a dedicated data center class rate schedule, docket implementation parameters, marginal cost of service and cost allocation methodologies, Rule I updates, special contract authority, CIAC, implementation of HB 2021 and HB 3546, large customer queues, and reporting requirements, as discussed herein. Each issue and position is reflected in the heading of each section and

[45] *Id.*

correlates to the similarly numbered item in the contested issues and position statement.[46] Taken together, these components form an integrated, interdependent framework designed to allocate costs based on cost causation while protecting residential and other non-large-load customers. Accordingly, PGE requests approval of the proposal in its entirety as set forth herein.

Because the subjects and topics are closely intertwined, a decision on any single issue will necessarily affect the operation and effectiveness of others. PGE's comprehensive recommendations are meant to provide holistic changes and, if adopted together, the resulting changes meet or exceed protections for other customers compared to other jurisdictions.[47] If certain aspects of the proposal are rejected or modified, the effectiveness of the proposal would be undermined and it could materially delay or negate customer benefits. For example, the positive impact of decreasing residential rates will only occur if PGE's proposal to adjust marginal cost allocation across all customer classes and update of the Net Variable Power Cost through the energy growth modifier is approved.[48] Absent approval of these interconnected components, those benefits cannot be realized. Likewise, without approval of a designated customer class for data centers, costs associated with their growth cannot be allocated directly and transparently to data centers causing such costs. Similarly, as another example of the interwoven nature of the proposal, the adoption a new, marginal cost allocation is coupled with an energy efficiency cost allocation modification, which will allow PGE to implement a methodological adjustment that better reflects the residential investment in system-wide energy efficiency when forecasting class coincident peaks for generation and transmission cost allocation. Rejection or substantial changes to these proposals will block these beneficial

[46] PGE's Position Statement and Contested Issues List (January 14, 2026).
[47] PGE/300, Fagan-Frayer/27
[48] PGE/400, Ferchland-Barrow-Jose/7, Table 1.

changes or, at a minimum, significantly delay passing the benefits of these changes through to our customers.

Upon approval, PGE will be able to incorporate a growth-pays-for-growth component to the current allocation methodology that centers on class pressure on the overall system peak, applies consistently across customer classes, and remains workable over the long term.[49]

## A. Docket Scope

Since the final order directing the opening of UE 430 in 2023 through today, the scope has always been broader than data centers as evidenced by the changes made to Rule C and Rule I in UE 430 and the issues list for this docket outlined in the ALJ's initial scoping ruling.[50] Further, if the scope were merely data centers, the changes proposed would not have the positive, protective impact they will have across other customer classes.[51]

### 1. Should the scope of this docket be limited to large load data centers under HB 3546?

***The Scope of this Docket Has Always Been About the Impact on all Customers from All Large Load Customers, Not Just Data Centers***

The scope of this docket was clear from the beginning in its applicability to all large load customers and, thus, it impacts the terms of service for customers other than large load data centers under HB 3546.[52] In PGE's 2024 general rate case, the Commission adopted a stipulation that all parties agreed with, which is that Staff "will propose to open an investigation to address new load connection costs […]" The Commission found that "[w]ith the fast pace and ***large***

[49] PGE/400, Ferchland-Barrow-Jose/2.
[50] Ruling (May 20, 2025).
[51] PGE/400, Ferchland-Barrow-Jose/6 at 3-4.
[52] PGE/400, Ferchland-Barrow-Jose/6 at 3-4.

***scale of new large load connections*** potentially emerging in our state, ***we need to promptly consider both the needs of those new large customers and the potential costs and risks to other customers***. […]"[53] (emphasis added) (October 30, 2023). The docket ordered became *Investigation into New Load Connection Costs*, UE 430, opened on December 1, 2023, to "[…] address both the interim tariff and the investigation required by Order No. 23-386."[54] In turn, the Commission in UE 430 directed that this instant docket be opened to "investigate the following non-exclusive scope: further modifications to Rule C and Rule I, and PGE's marginal cost study's treatment of transmission costs ***for large customers***."[55] (Emphasis added). In the ruling promulgating the issues list, ALJ Mapes reflects this broader scope, holding that the core issues in this docket are "evaluating and ***appropriately allocating the cost to serve large customers*** […]"[56] (emphasis added).

Further, HB 3546, which ordered the creation of a data center-specific customer class, was not signed into law until several months after the opening of this docket.[57]

The record is clear: this docket is broader than Schedule 96.

## B. Schedule 96 and Other Associated Changes

To meet the requirements of the POWER Act, a new schedule must be created. As discussed herein, PGE has proposed a schedule that is fully compliant with the POWER Act.

---

[53] Dkt. UE 416, Order No. 23-386 (October 30, 2023).
[54] Dkt. UE 430, Memorandum Opening Docket of Status Scheduling Conference (December 1, 2023).
[55] Dkt. UE 430, Order No. 25-091 (March 6, 2025).
[56] Ruling (May 20, 2025).
[57] Oregon State Legislature, *Oregon Legislative Information, 2025 Regular Session, HB 3546 Enrolled* (June 16, 2025), available at https://olis.oregonlegislature.gov/liz/2025R1/Measures/Overview/HB3546.

## 2. Should the Commission approve large load data center customer class and the other provisions included in Schedule 96 as proposed in PGE Exhibit 410?

***Schedule 96 Should Be Approved***

PGE respectfully requests that the Commission approve Schedule 96[58] as proposed by PGE in Exhibit 410. This schedule establishes a new rate schedule specifically for large data centers and ensures that data centers pay for their cost of service in terms of incremental distribution, transmission, and generation assets, and are not subsidized by other customer classes.

Further, as discussed in more detail in Sections 49-51 and 54, Schedule 96 is fully compliant with the POWER Act, HB 3546 and should be approved based on the factors the law identifies for the Commission consideration under the POWER Act.[59] Specifically, Schedule 96 is aligned with the language in Section 2.2 of the POWER Act, which orders utilities to "provide for a classification of service under ORS 757.230 for retail electricity consumers that are large energy use facilities,"[60] directing that "the classification of service must be separate and distinct from classifications of service for other commercial or industrial retail electricity consumers and have its own tariff schedule."[61] New Schedule 96 meets these requirements and should therefore be approved.[62]

[58] Parties anticipate filing a stipulation to this effect on or after February 4, 2026. This section is included in the Opening Brief for completeness as it appeared in the contested issues list and the position statement, but we expect the issues to be addressed only in connection with the stipulation; to the extent issues related to Schedule 96 go beyond the rate design issues that are part of the stipulation, they are addressed in other issues in this Opening Brief (e.g, minimum demand charges in Section 26 and Staff's flat billing proposal in Section 27).
[59] PGE/400, Ferchland-Barrow-Jose/2, 4 (citing PGE/100, Ferchland-Barrow/9-13); *see also generally*, PGE/400, Ferchland-Barrow-Jose/4-5, 50.
[60] ORS § 757.292 (2).
[61] *Id.*
[62] PGE/100, Ferchland–Barrow/9.

### 3. Should a subclass of customers be created within Schedule 96 as part of this docket to specifically apply to data centers that have asset-backed flexible loads?

***There is No Evidence to Support the Creation of a Subclass Within Schedule 96 at this Time***

While certain parties have suggested that Schedule 96 should include a subclass for flexible loads from its inception, PGE does not support the idea because there is not sufficient information available in this docket to support the formation of a subclass of customers at this time.[63] Though PGE recognizes that increased flexibility could offer potential benefits, there currently is not enough information or evidence offered to determine whether a flexible subclass is warranted at this juncture and what the appropriate eligibility requirements would be for such a subclass. Advancing specialized subclasses without a clear understanding of eligibility, costs, and benefits is not appropriate as this would reduce transparency, fragment the tariff, and create administrative complexities. It is important to be thoughtful when implementing a flexible subclass and PGE's rate design seeks to create customer classes that are broadly applicable rather than narrow and highly specialized. Further, PGE already incentivizes flexibility through programs that provide the potential access to additional allocated system capacity or accelerated energization (which is discussed further in Sections 52-53, below).[64] While PGE remains open to further evaluation as additional information becomes available, at this juncture, the new schedule should not include a subclass.[65]

---

[63] PGE/400, Ferchland-Barrow-Jose/30, 49.
[64] PGE/400, Ferchland-Barrow-Jose/65.
[65] PGE/400, Ferchland-Barrow-Jose/49.

**4. Should a surcharge for non-cost effective energy efficiency as proposed by CRITFC and the Coalition be included in Schedule 96?**

***Schedule 96 Should Not Include a Surcharge for Non-Cost Effective Energy, But PGE is Open to Further Evaluation of Such a Surcharge***

PGE customers fund a robust portfolio of energy efficiency and demand side management proposals through an established, dedicated schedule. Schedule 109 collects funding requested by the Energy Trust of Oregon (ETO) to administer energy efficiency programs in PGE's service territory, including both cost-effective and non-cost-effective measures. Schedule 96 customers must also pay Schedule 109 charges, and thus, the proposal for an additional surcharge would be duplicative.

While we appreciate the intent of what parties are proposing, the ETO is the sole administrator of cost-effective energy efficiency programs in PGE's service territory and is responsible for meeting the energy efficiency acquisition targets set in PGE's Integrated Resource Planning and Clean Energy Planning (IRP/CEP) and a separate data center-only charge for additional energy efficiency may unnecessarily complicate ETO planning and acquisition work. Funding of nearly $167 million is allocated to achieve these targets in 2026 alone. ETO targets these dollars toward least-cost energy efficiency acquisition.

PGE recognizes the importance of ETO funding and welcomes additional evaluation of data center class contribution to ETO in a non-bypassable manner which benefits the service to these customers and the system. This evaluation should be informed by Schedule 109, ongoing work, and applicable laws, including laws that define how large customers contribute to energy efficiency acquisition.[66]

### 5. Should PGE's proposed changes to the Schedules 89 and 90 to add a demand charge instead of a volumetric charge for fixed generation recovery be adopted?

#### *Schedules 89 and 90 Should be Allowed to Have a Demand Charge for Fixed Generation Recovery*

As PGE will have multiple schedules for larger nonresidential customers with the creation of Schedule 96, it is important that there is consistency across the classes for demand charges to avoid an unintended consequence of a customer shifting from one class to another and shedding their prior demand requirement. By approving the use of a demand charge for fixed generation recovery in place of the current volumetric charge in Schedules 89 and 90, there will be rate design consistency for customers who migrate rate schedules as they grow[67] because the Commission's approval will expand generation demand charges to cost-of-service customers on Schedules 89, 90 and 96. Currently, only Schedules 83 and 85 have generation demand charges. The application of minimum demand charges for fixed generation proposed for Schedules 89, 90, and 96 is discussed further in Section 26, below (recovery of net variable power costs via Schedule 125 would continue to be recovered with time-variant volumetric charges).

---

[66] PGE recognizes that a legislative option to increase energy efficiency funding would be to lift the caps on the combined annual amount charged based on consumer use, which is currently a maximum $4 million for even the largest customers. (HB 3141 §3; Oregon Laws 2021 c.547 §3).
[67] PGE/100, Ferchland-Barrow/37.

### 6. Should all Schedule 96 customers be required to pay the maximum contribution allowable under HB 3141?

***Schedule 96 Customers Should Not Face Maximum Charges Under HB 3141***

Requiring Schedule 96 customers- and only Schedule 96 customers – to pay the maximum amount allowable under HB 3141 will result in disparate treatment of one customer class, and it is not consistent with the law, which clearly does not require that a certain customer class pay the maximum amount. Rather, ORS § 757.054(3) sets forward specific dollar limits to energy efficiency funding based on the size of the customer and it does not require each customer within a particular schedule to pay the maximum amount regardless of size. Applying the maximum amount allowable would result in data centers paying distinctively different and higher costs to fund energy efficiency than other customer classes, including other large industrial customers.[68] If the Oregon Legislature had found it appropriate to require a specific customer class to automatically pay the maximum amount, it would be reflected in the statutory language.

In absence of that legislative direction, PGE does not consider it appropriate to arbitrarily require a higher amount for Schedule 96 customers when instead they are supposed to pay based on actual size. While PGE understands funding concerns for energy efficiency, we instead recommend that the Commission agree to our proposed methodological adjustment (as discussed in Section 10) so that our resulting cost assignments reflect the residential investment in system-wide energy efficiency when forecasting class coincident peaks for generation and transmission cost allocation.[69] This will account for energy efficiency investments and not compromise

[68] AWEC/300, Kaufman/16-17.
[69] PGE/400, Ferchland-Barrow-Jose/10.

fairness, in contrast to the suggestion that Schedule 96 customers should pay the maximum and higher than legally required amount.

## C. Implementation

This docket directly impacts all existing customers in and all prospective customers for PGE's system, not merely data centers. To ensure rates are fair, just, and reasonable for all customers and that growth is entering into the system in a responsible way and being paid for by those causing the growth, the changes from this docket should be implemented swiftly.

7. **How should the Commission decision in this docket be implemented? Should it be implemented as a compliance filing to the Commission final order in this docket or as part of PGE's next general rate case or some other alternative?**

***The Commission's Decisions Should be Implemented as Soon as Practicable***

The decisions made in this docket, if approached holistically as PGE recommends, will comprehensively change the way costs are allocated in a manner that benefits the entire system and its customers. As such, the Commission should direct PGE to implement changes through a compliance filing as soon as practicable after the conclusion of this docket. The final order should require PGE to update rates consistent with the decisions in this docket and the revenue requirement approved in PGE's last general rate case, UE 435, and annual update tariff, UE 452. These updates will not change the revenue requirement.[70] The implementation should not be delayed until the next general rate case or through another mechanism as there is no reason to delay and doing so would postpone the application of marginal cost principles adopted in this

[70] PGE/100, Ferchland-Barrow/8, (*see also* CUB/300, Jenks/23, updating prior position, stating most recently in testimony, "[w]e can realign the existing revenue requirement to meet the requirements of HB 3546 at the end of this case.")

docket for months. Implementing changes now allows PGE to immediately apply lower rates to residential and small commercial customers. Delaying these decreases would be contrary to the core intent of this docket and unreasonably denies immediate relief to these customers. Additionally, applying these changes now will trigger consistency across cost-recovery proceedings moving forward, including PGE's current and next power cost filings and any filings to incorporate growth-related assets.[71] Data centers and large load customers seek to enter PGE's service territory in the coming days and weeks, not months from now or when a later rate case occurs. This docket includes decisions that will implement many aspects of how these new data centers and large load customers are added to our system, and delaying implementation of the changes does not timely add the stronger protections proposed by PGE for all customers, such as minimum demand charges.

Depending upon the nature of the final order in this docket, PGE and the parties may require additional time to understand, analyze, and implement the ratemaking impacts of the final order. Given the uncertainty of the precise contours of the final order, PGE does not advocate for a specific timeframe for implementation other than it should be as soon as practicable after the conclusion of this docket.

### D. Marginal Cost of Service and Cost Allocation

Today, regardless of the type of PGE retail customer, cost allocation is determined by system use. In a system built with sustained, incremental growth across most customer classes over decades, this approach worked. This paradigm is no longer fair to our customers as PGE faces an influx of new data centers and large loads that seek to join our existing, networked, integrated system that is filled with established customers paying based on their own system use.

[71] PGE/200, Ferchland-Barrow/4, 5.

If we maintain the current approach to cost allocation, our customers in this traditional pay-for-usage framework will face a dramatic increase in costs even though they are not the cause of the data center or large load growth in the system. Therefore, in this case, PGE proposes a new approach: allocating the cost of investments made to serve growth to customer classes that are causing growth and, therefore fewer costs would be allocated the customers who are not.

We propose changing the cost allocation methodologies in a manner that requires growth to pay for growth while recognizing that transmission and generation assets and investments related to growth are typically network resources that benefit all customers. Thus, through the application of the PGM (discussed further in Sections 8, 13 and 14) we propose to assign a proportionate, high cost upfront to the customer classes, such as the data center class, who are the catalyst of the growth in system peak and the new assets and investments made to serve that load growth, then transition back to a cost-of-service model over time, which is a reflection of the transmission and fixed generation assets being part of an integrated, networked system that benefits and is used by all customers. We think this transition makes sense because these are network resources and all customers are benefiting from them. Nevertheless, and as discussed further below, we are open to revisiting PGM over time and have suggested a comprehensive reassessment be conducted no later than year 10 before growth-related assets would be transitioned out of the PGM and allocated in the same manner as non-growth assets.

Implementing a new method to allocate more marginal costs for customers causing growth is needed with this rapid influx of growth to our system. One way to understand why we need a new approach is to look at how cities handle roadways during a period of sudden development. If a large company moves to a city, bringing thousands of employees to a previously vacant lot where they build a new campus, the city might need to build new roads in that area. Even if one end of a road serves primarily as the company's driveway, the rest of the road network that is developed is open to everyone. The new infrastructure benefits everyone in the area, ensuring people can move freely and avoid traffic jams. And if one road is backed up or closed, people can now take another route. The electric grid works the same way: adding new transmission gives power more paths to flow, improving reliability and resilience for everyone as the networked system is now larger, with more routes and generation capacity.

The challenge becomes how to price and allocate the costs of these new roads because, while the roads are being built rapidly at a relatively higher cost to support the new company, there is no road for others to use early on, and then use of the roads increases gradually over time as the area around it adjusts and expands. For this reason, it makes sense for growth upfront to be proportionately borne by the new company in this example, as the cause for the growth, and over time for the cost of the roads to be incorporated into another cost allocation model that allows for costs to be shared by all of the users of the road network that are now benefiting from its expansion. At the same time, the company will have achieved its growth potential, expanded its use of infrastructure and contributed a larger portion toward the costs of all roads via more traditional channels (e.g., increased tax base from employees).

Similarly, PGE's proposed new marginal cost allocation initially assigns a proportionately higher cost to the cause of the growth – increasingly the data center class – shielding the customers who are not the causing the growth from the upfront costs. As the data center customer expands, becoming a larger portion of the grid and reaching their final allocated capacity, they will continue to bear their fair share of costs through more traditional allocation methods based on contribution to system peak and proportion of overall usage. If a data center, or other large load customer, exits service before reaching their final allocated capacity, the combination of protections and requirements incorporated in PGE's proposal will protect against PGE's customers paying for stranded costs. Increasing proportional upfront marginal cost to ensure that customers causing growth pay for growth and then, over time, transitioning to charge customers for system use reflects a sensible approach to recognizing system benefits to all customers without unfairly assigning costs.

### 8. Based on the marginal cost study, how should the cost of fixed generation be allocated?

#### *Allocation of Fixed Generation Should Reflect Class Contribution to System Peak and System Peak Growth Over Time*

To ensure that customer classes that are causing growth in PGE's system are paying their fair share of the cost of that growth, the Company needs to adjust its cost allocation methodologies for fixed generation and transmission costs. PGE proposes using the PGM, which will allow it to assess and allocate costs on the basis of class growth, specifically growth that results in higher system peaks. PGE seeks approval for the PGM as the most appropriate adjustment to allocation methodology after evaluation of options and its existing methodology, which is based on a snapshot of class contributions to system peaks for the following year only. Class contributions to system peaks are measured as forecasted class demand coincident with the overall system peak (i.e. coincident peak or CP) in a given month.  Fixed generation costs are currently allocated on the average CPs of the four typical peak months (December, January, July and August; 4-CP) and transmission costs are currently allocated on the average CPs for all months (12-CP). While evaluating options, PGE prioritized approaches that uphold the Bonbright principles- particularly fairness in cost causation, customer understanding, and administrative simplicity.[72] The proposed PGM will be combined with the energy growth modifier (EGM) in the updated net variable power costs (NVPC) as discussed further in Section 16, to result in a new cost allocation so that growth in the system is proportionally assigned to the customer class that is causing it.

The PGM enables allocating fixed generation costs based on class contribution to system peak through this new calculation that includes growth-related investments' allocation to the customer classes most responsible for increasing the system's peak demand.[73] PGE's PGM is a natural and reasonable evolution from existing coincident peak methodologies that better reflects current system dynamics.[74] Importantly, PGE's proposal will allow for differentiation in cost allocation for growth and non-growth fixed generation[75] and result in the allocation of the former being informed by the amount driven by class changes in contribution to system peak, as a proportion of the growth in overall system peak, over a period of years. A simplified example is: all but one class did not change their demand during system peak hours over a period of three years while one class grew by 300 MW during peak hours, resulting in a 300 MW increase to system peak over the 3-year period. The PGM would allocate 100% of growth-related costs during this time period to the fixed generation for the particular growing class in and none to all other customer classes.

PGE's proposed PGM aligns with cost-causation principles, reflects the realities of infrastructure planning, and supports more equitable and efficient allocation of system costs. The PGM is designed to distinguish between customer classes that are driving current peak loads versus those driving growth in peaks over time. The PGM would separately allocate the costs of

[72] PGE/100, Ferchland-Barrow/15.
[73] PGE/100, Ferchland-Barrow/19.
[74] PGE/200, Ferchland-Barrow/46.
[75] PGE/100, Ferchland-Barrow/20

incremental fixed generation and transmission investments made up to ten years prior to the test year, specifically those investments driven by system growth caused by that customer class. The PGM, in combination with the EGM, minimum demand requirements for large load customers, exit fees, and other contractual protections, helps ensure that cost-of-service allocations are better balanced, forward-looking and aligned with actual system impacts. It reduces the risk of cost shifting and supports more sustainable and equitable rate structures across all customer classes.[76]

#### a. The PGM Aligns with Cost-Causation Principles

The PGM enhances fairness in cost allocation by introducing a growth-sensitive approach to assigning generation and transmission costs ensuring that customer classes driving peak growth are more accurately assigned the costs of the infrastructure built to serve them.[77] Traditional CP-based allocation methods offer a static, single-year snapshot of peak contributions in the target year. The PGM adds critical nuance by measuring customer class growth over time, providing a more robust reflection of cost causation, especially in rapid load change. This flexibility applies both to the influence of the PGM in overall fixed generation and transmission allocations, as well as class allocations within the PGM.[78]

PGE forecasts indicate that two customer classes are currently contributing most to system peak increases: the new data center class, due to its rapid expansion, and the residential class, which despite more modest growth as a percentage of class CP, represents such a large base that even modest growth results in a significant absolute increase in the peak demand portion of overall system growth.[79]

---

[76] PGE/100, Ferchland–Barrow/19.
[77] PGE/100, Ferchland-Barrow/25; *see also* PGE/200, Ferchland-Barrow/8-9.
[78] PGE/100, Ferchland-Barrow/23.
[79] PGE/100, Ferchland-Barrow/24.

The PGM adds a layer that isolates the impact of peak growth—ensuring that the revenue requirement for growth-related investments is allocated to the customer classes most responsible for increasing the system's peak demand. Currently, PGE allocates fixed generation costs using a 4-CP allocation method and transmission costs using a 12-CP allocation method, both of which allocate costs based on class contribution to system peak for the target year. PGE's proposed PGM would instead calculate class growth between two test years, measured in terms of average contribution to system peak (4-CP or 12-CP), as a percentage of overall cost of service system peak growth during the same timeframe, where the sum of class CP deltas is equal to the system peak delta.

### b. The PGM reflects the realities of infrastructure planning

PGE proposes this allocation method be applied to the portion of fixed generation and transmission functionalized revenue requirements that are associated with growth-motivated investments specifically made to meet increased system demand. These are investments PGE would make regardless of customer energy load growth and driven by changes in demand that motivate increased system capacity. Today, fixed generation and transmission costs are allocated to customer classes using the typical 4- or 12-CP methodology consistent with long standing regulatory practice. Here, PGE proposes a three-year backward-looking window (increasing to 10 years over the subsequent years) for assessing both incremental revenue requirements that can be characterized as growth investments and the PGM components (system peak growth and class coincident peaks). The three-year window smooths short term volatility and aligns cost allocation with actual investment drivers, avoiding distortions that could result in lumpy infrastructure investments or customer load additions or shifts in any single year.[80]

[80] PGE/100, Ferchland–Barrow/20.

The PGM is also responsive to system conditions. In the near future, when significant investment and purchases are needed to meet increasing load expectations, a larger portion of transmission and generation revenue requirement will be allocated using the PGM as compared to typical coincident peak methods. In periods of slower growth and proportionately less spending on growth-related assets, the PGM would have less influence on cost allocations. Considering class-level allocations within the PGM, the methodology accounts for a range of growth contribution scenarios. If one customer class is driving 100% of system peak growth, that class would be allocated 100% of growth-related revenue requirement initially for the first few years the asset is in service, and later for a rolling period of 10 years. If all customer classes are growing at the same rate (such that their proportional contributions to system peak are constant), the PGM would allocate growth-related revenue requirement in the same manner as 4- or 12-CP and have no incremental influence on class allocations.

**c. The PGM allows for an efficient allocation of system costs**

Measuring each customer class's contribution to system peak growth is essential for fairly allocating the costs of infrastructure investments needed to serve rising demand. A class's share of system peak in a single year tells only part of the story—what matters for cost causation is which classes are driving growth in that peak over time, which is what ultimately triggers the need for new generation and transmission resources.

For example, over the past three years, the residential class, while showing only modest growth in relative terms (in terms of 4-CP, the class increased by about 6%), accounted for 45% of the growth in system peak during the four highest use months, prior to accounting for adjustments made for energy efficiency funding. When accounting for these adjustments, the residential class contribution to growth was 28%. Customers eligible for Schedule 96, which currently represent just 4% of the system peak during the four highest use months, have grown five-fold since 2022 and contributed 50% unadjusted to total system peak growth during the same period, and 51% when adjusting for energy efficiency funding.[81] Together, these two classes (Schedule 7 and 96) have been the primary drivers of the recent growth in system peak. Relying solely on forecasted peak contributions would place most of the incremental costs on residential customers and under-assign costs to Schedule 96. Allocating new costs based on class contribution to system peak growth instead yields a more equitable and efficient cost structure. If PGE were to solely allocate all new costs to Schedule 96, they would bear an unfair burden because they are not the only contributors to the growth in the system peak.[82]

**9. Based on the marginal cost study, how should the cost of transmission be allocated?**

***Allocation of Transmission Should Also Reflect Class Contribution to System Peak and System Peak Growth Over Time***

As expanded upon in more detail in Section 8 regarding fixed generation, transmission costs should be allocated based on class contribution to system peak through the same calculation that includes growth-related investments' allocation to the customer classes most responsible for increasing the system's peak demand.[83] PGE's proposed PGM provides for this allocation and should therefore be approved. Approval of PGE's proposal will allow for differentiation in cost allocation for growth and non-growth transmission.[84]

---

[81] PGE/400, Ferchland-Barrow-Jose/13-14.
[82] PGE/100 Ferchland–Barrow/25.
[83] PGE/100, Ferchland-Barrow/19.
[84] PGE/100, Ferchland-Barrow/20.

**10. What role should energy efficiency play in the marginal cost study allocation?**

***Residential Investment in Energy Efficiency Should Be Fully Reflected in Class Contribution to System Peak Analysis***

PGE supports a methodological adjustment that reflects residential investment in system-wide energy efficiency when forecasting CP for generation and transmission cost allocation.[85] PGE's position here is directly responsive to CUB's energy efficiency funding concerns. This was not included in PGE's initial proposal in this docket because energy efficiency does not automatically factor into the marginal cost study allocation and the cost of acquiring energy efficiency is not part of PGE's fixed or variable generation requirements but is instead reflected in a reduced corporate load forecast.

However, PGE acknowledges that, in addition to the system benefits of energy efficiency, there are participant benefits for those customers receiving energy efficiency within ETO programming. Specifically, energy efficiency participants have lower energy demand than they otherwise would, which impacts their class's contribution to system peaks and allocated generation and transmission costs.[86] PGE's proposal would adjust forecasted class coincident-peaks to better align with proportional funding towards ETO's achieved summer and winter system peak reductions achieved by ETO based on funding by customer class.[87] This will allow appropriate accommodation for energy efficiency, even though it did not automatically factor into the original marginal cost study allocation.

Of note, PGE passes customer dollars to ETO, and it is then ETO who decides how those dollars are invested to most cost-effectively realize savings for the benefit of the system. PGE

[85] PGE/400, Ferchland-Barrow-Jose/10.
[86] PGE/200, Ferchland-Barrow/15.
[87] PGE/400, Ferchland-Barrow-Jose/8.

believes that a more appropriate long-term adjustment to handle recent misalignment of class contributions to ETO funding and cost-effective energy efficiency participant benefits be considered within the context of how ETO funding is collected from each customer class, which is outside the marginal cost study.[88]

**11. Should changes be made to the marginal cost allocation for distribution?**

***Distribution Marginal Costs Should Be Changed***

To fairly allocate marginal costs across customer classes, the marginal costs of distribution should also be updated so that customers are allocated their share of the revenue requirement based on the cost to serve the customer class.[89] As part of this update, substation costs would be differentiated by customer class, which would recognize the higher price of an industrial substation versus substations that serve commercial and/or residential customers and improves cost accuracy across all classes;[90] parties have indicated agreement that this differentiation should occur.[91]

As Staff correctly points out in their testimony, with the creation of a data center rate class, Schedule 96 customers will be paying the monthly revenue requirement for their incremental distribution assets each month.[92] The creation of Schedule 96 will ensure the distribution assets to serve this customer class will not be double counted and spread to other customer classes via the existing allocation methodology. PGE's updated distribution marginal cost study includes Schedule 96 (and the contracted distribution capacity for customers within

---

[88] PGE/200, Ferchland-Barrow/15.
[89] PGE/200, Ferchland-Barrow/10.
[90] PGE/100, Ferchland-Barrow/10, 13.
[91] Parties anticipate filing a stipulation to this effect on or after February 4, 2026. This section is included in the Opening Brief for completeness as it appeared in the contested issues list and the position statement, but we expect the issues to be addressed only in connection with the stipulation.
[92] Opening Testimony of Bret Stevens, Staff/100, Stevens/34 (August 11, 2025).

this class) so that allocations of the overall distribution revenue requirement for each customer class will reflect PGE's cost to serve the customer class. Further, PGE proposed a change to distribution minimums which further addressed Staff's concern that operational and maintenance costs will not be sufficiently recovered from Schedule 96 customers.[93] This change, when coupled with the proposed minimum distribution demand charge, as discussed further below, will ensure that customers appropriately pay for their differentiated distribution marginal costs. For these reasons, PGE respectfully requests that the Commission approve PGE's proposal to update the marginal cost allocation for distribution.

**12. Should the Commission adopt CUB's proposal that distribution assets should not be included in rate base until applicant comes online (CUB/100, Jenks/22)?**

***Distribution Assets Should Be Included in Base Rate When They Are Placed into Service***

Distribution assets, which are part of the delivery network and consist of local area power poles, transformers, conductors, meters, substations and other equipment, are placed in-service pursuant to current Commission-approved planning assumptions—distribution assets connected to PGE's system and determined to be prudent are used and useful.[94] PGE's position that distribution assets should be included in base rates reflects the Commission's current regulatory policies and the legal requirement that only assets that are presently used and useful may be included in rates. This framework is adequate to address any concerns based on the "used and useful" standard,[95] such as CUB's proposal. CUB's proposal would change the existing framework, resulting in the exclusion of costs from rates that were prudently incurred for assets

[93] PGE/200, Ferchland-Barrow/10.
[94] PGE/400, Ferchland-Barrow-Jose/31.
[95] PGE/400, Ferchland-Barrow-Jose/32.

that are used and useful. There is no legal or evidentiary basis for that approach. The Commission should therefore reject the proposal to exclude distribution assets from rate base as proposed by CUB.

While PGE is open to studying how emerging technologies and evolving system uses affect long-term planning and cost allocation, the used and useful determination should not be conditioned on customer interconnection timing for distribution assets. If the asset is connected to the system and energy is flowing through the asset, it is being used by the system and it is useful. Conditioning rate base recovery on physical interconnection would introduce uncertainty around recovery of prudent investments and undermine the Commission's prior prudence determinations. PGE therefore recommends that the existing used and useful framework remain unchanged, and that any exploration of evolving distribution system functions should occur prospectively and without retroactive ratemaking impacts.[96]

**13. Should PGE limit the assignment of growth-related costs?**

***Growth-Related Costs Should Have an Initial Timeframe of Assignment of Three Years and Extend to Ten Years Over Time***

As discussed previously and discussed in more detail below, PGE should be permitted to limit the assignment of growth-related costs to a three-year initial timeframe, which will then be extended by one year annually until it reaches a total of ten years, after which one additional year rolling will be added (maintaining a total of ten years for assignment of a growth-related cost). This is an appropriate amount of time to limit the assignment of growth-related costs and guard against class-to-class subsidization, which would occur if the assignment was permanent. Starting with a three-year period and extending it over time allows the PGM to be updated as

---

[96] *Id.*

needed so that allocations remain consistent with changes in the mix of resources serving load and customer usage patterns.[97] This will also allow PGE to transition assets from a higher marginal cost allocation for growth back to a cost-of-service model over time, which is a reflection of the transmission and fixed generation assets being part of an integrated, networked system that benefits and is used by all customers.

It would not be appropriate to keep assets initially built for growth in the PGM in perpetuity. An initial three-year period extending to a ten-year period aligns with the system benefits ultimately enjoyed by every customer class and, importantly, aligns with the POWER Act directive that require utilities to protect against cross-subsidization. Requiring assets initially built for growth to stay in the PGM in perpetuity overlooks the system benefits provided by these assets, which are used by and benefit every customer class. While PGE agrees that the initial driver of the investment should be recognized, it cannot be ignored that these investments enhance the reliability and stability of the entire system. Under a permanent assignment, a customer class that does not experience growth for an extended period would never contribute to these investments, despite continuing to benefit from them.

Further, PGE's proposal is intended to align with the directive in POWER Act, which requires utilities to ensure that other customer classes are not subsidizing data center customers. More broadly, just and reasonable rates should not permit clear cross-subsidization among classes, and this proposal is designed to be sustainable long-term and prevent cross-subsidization. While significant data center development has occurred elsewhere in Oregon earlier, initiating this mechanism beginning in 2022 is reasonable because this reflects the beginning of large load data centers being on PGE's system and included in the load forecast.

---

[97] PGE/400, Ferchland-Barrow-Jose/4, 8, 16, 17.

Starting with a three-year period and expanding it over time allows the PGM to be updated as needed so that allocations remain consistent with changes in the mix of resources serving load and customer usage patterns.[98] If the assets are assigned as growth in perpetuity, it results in certain customer classes paying a higher proportionate cost for the lifetime of the asset, even though all other customer classes are benefiting from the same asset – which would mean the customer class with the growth asset is now subsidizing other customer class.

In addition, requiring separation in perpetuity would be administratively unreasonable, unworkable, and is not needed. This would require PGE to separately track and maintain the revenue requirements of specific generation assets over time, which would be administratively burdensome and functionally similar to direct assignment—an approach that both Staff and PGE agree should be avoided for fixed generation. It would be unreasonable and unworkable to require, decades from now, PGE to conduct a 40-year lookback to determine growth drivers and associated revenue requirements for long-lived assets.[99] PGE did not anticipate the need for this type of mechanism when investments were made a decade ago, and therefore we do not have information that would allow us to distinguish between growth-related and non-growth assets over that period. Further, the contribution of Schedule 96 customers to the system peak, after growth assets are old enough to no longer be subject to the PGM (10 years in PGE's proposal), is expected to increase and be significant. This would allow Schedule 96 customers to continue to pay for a substantial portion of these costs based on their usage during system peaks in the same way that other customer classes will pay for the benefit they receive from these parts of the integrated electrical system.

---

[98] PGE/400, Ferchland–Barrow-Jose/17.
[99] PGE/400, Ferchland–Barrow-Jose/16.

## 14. Should PGE's Peak Growth Modifier be adopted? If so,

***PGE's Peak Growth Modifier (PGM) Should Be Approved***

As established, the PGM enhances fairness in cost allocation by introducing a dynamic, growth-sensitive approach to assigning fixed generation and transmission costs and ensures that customer classes driving peak growth are more accurately assigned the costs of the infrastructure built to serve them.[100] The Commission's approval of the PGM would help ensure that each customer class pays its fair share, supports long-term system planning, and avoids cross-subsidization. The use of the PGM provides a more accurate and equitable foundation for rates and it is an approach that benefits the entire system and all customers, not one particular class or data centers.[101] Further, the use of PGM as proposed by PGE will allow for a gradual transition as more growth comes onto the system and is needed to ensure that existing customers do not bear imbalanced costs associated with that growth.[102] The goal of PGE's proposal is to ensure that marginal cost of service studies and overall cost allocations through the PGM more accurately reflect the costs caused by, and the benefits received by, customer classes driving system investments—primarily new large loads. Instead of allocating costs based solely on test year contribution to peak demand, as discussed, PGE proposes assigning incremental fixed generation and transmission costs from the past three years to the classes that caused peak load growth for this initial implementation, introducing an additional year each year, until ten years are reached and maintained on a rolling basis. This will better align with cost causation and minimize cost-shifting to classes with flat or declining load. These modifications ensure classes

[100] PGE/100, Ferchland-Barrow/23.
[101] *Id.* at 13.
[102] PGE/400, Ferchland-Barrow-Jose/28.

who are not driving new system investments are not subsidizing growth related investments to serve new load.

For these reasons, and as discussed in Sections 8 and 13 above, PGE respectfully requests that the Commission approve PGE's proposed PGM.

**a. What is the appropriate length of time that growth-related assets should be allocated pursuant to PGE's Peak Growth Modifier?**

***The PGM Should Begin at Three Years and Then Extend Until a Total of Ten Rolling Years***

The Commission should find that the appropriate length of time for the PGM is an initial three-year period (to start at three years from 2022 to 2025) that will extend with one year increases annually to a total of a ten-year period before rolling forward one year annually.[103] During the initial ten-year period, the PGM can be comprehensively reassessed as needed. The phased approach over ten years balances stability with accuracy and avoids locking in allocations that may become misaligned with actual system dynamics.[104]

Requiring that an asset be assigned as growth-related in PGM in perpetuity, such as suggested by Staff, is unreasonable because these are system assets that enhance the reliability and stability of the entire system. Classifying assets as growth-related in perpetuity would result in customers benefiting from investments that they do not contribute to, in some instances permanently benefiting without paying any portion of the costs, and function similarly to direct assignment for fixed generation, which is something Staff and PGE agree should not occur.[105]

---

[103] PGE/400, Ferchland-Barrow-Jose/4, 8, 16.
[104] PGE/400, Ferchland-Barrow-Jose/16.
[105] *Id.*

For these reasons, and as discussed in Section 13, PGE respectfully requests that the Commission adopt PGE's requested timeframe for the PGM.

### b. Should AWEC's proposal for weather normalization of PGE's Peak Growth Modifier for generation and transmission be adopted?

***Weather Normalization Is Already Part of the PGM***

The Commission should reject AWEC's proposal regarding weather normalization because it is redundant to PGE's current methodology. As proposed by PGE, the PGM already appropriately minimizes the impact of year-over-year weather fluctuations and associated class responses by applying five-year average coincident peak factors to estimate target year coincident peak demand by class. Additionally, system peak growth is determined as the difference between forecasted peaks under normal weather conditions.[106]

AWEC raised a concern that PGE's measure of class contribution to system peak growth could conflate actual growth with year-over-year weather responses.[107] However, class coincident peak values are based on historical class contribution factors (i.e. coincident load factors) using actual usage data. These coincident load factors are calculated as the typical ratio between average class demand and CP, assessed for each calendar month over a five-year historical window. While this approach does not incorporate traditional weather normalization adjustments, it does minimize the impact of year-over-year weather fluctuations and associated class responses by applying five-year average factors to estimate target year coincident load factors. The forecasts of average energy usage and system peak demand to which these factors are applied reflect normal weather conditions as defined by PGE's load forecast. The energy deliveries forecast assumes gradual warming, the weather input is estimated based on historical

[106] PGE/400, Ferchland-Barrow-Jose/29, *citing* PGE's response to AWEC's data request 27 with Attachment A, provided as PGE Exhibits 405 and 406.
[107] PGE/400, Ferchland-Barrow-Jose/29.

weather data and warming trends. For peak demand, PGE's model uses 15 years of hourly historical weather data to simulate response under peak conditions.[108] Because PGE's proposal already adequately addresses AWEC's concerns, the Commission should reject AWEC's proposal for weather normalization.

### c. How should "growth-related" investments or assets be defined?

***Growth-Related Investments or Assets Have Straightforward Definitions***

As part of the established planning and procurement process, PGE already determines which investments (referred to interchangeably as assets), are defined as growth. This straightforward, objective approach is proposed to carry forward and be used for the designation for the purposes of the PGM and marginal cost allocation. These are simple, clear, easily followed, and consistent definitions:

Transmission investments (assets) are considered growth-related when they are triggered by new or increasing load, which will be documented within the project justification.

Generation investments (assets) are considered growth-related when they are triggered by the need for incremental capacity or energy to reliably serve increased demand.

Examples of growth-related transmission investments (assets) include:[109]

- Load-Driven System Upgrades – Projects needed because projected load will exceed system capacity and will introduce exceedance to thermal, voltage, or stability limits. Examples include:
    - Reconductoring lines to higher capacity;

[108] PGE/400, Ferchland–Barrow-Jose/29.
[109] *See generally* PGE/400, Ferchland-Barrow-Jose/25, 26 (setting forward a non-exhaustive list of examples, which in testimony included "large" and "large load," but these qualifiers have been removed here for clarity because the application of the "growth" definition will occur regardless of size of the project. *See* PGE/400, Ferchland-Barrow-Jose/21 ("Growth percentages calculated across *all classes* are meaningful only when applied to the total costs of *all growth-related assets*.)" (Emphasis original).

- New transmission line to serve load pockets or customer additions;
- Transformer capacity expansions; and,
- Grid Enhancing Technologies (GETs) - investments in advanced technologies such as dynamic line ratings or other solutions that increase the capacity of existing transmission infrastructure to accommodate load growth without traditional infrastructure expansion.

- New or Expanding Substations – Projects driven by new subdivisions, customers, inadequate capacity or voltage support due to load growth.
- Load Interconnection-Driven Upgrades – Projects for new interconnections, multiple new customers in a geographic area and for electrification (EV fleets, building electrification, etc.).

Examples of growth-related generation investments (assets) include:[110]

- New Capacity Additions – Investments for new renewable generation (wind, solar, etc.) when added to meet load growth and not policy compliance, battery storage and flexible demand-side (non-wires alternatives) to satisfy resource adequacy for growing peak demand.
- Upgrades or Efficiency Improvements – Projects to support load growth that are related to turbine upgrades that increase MW capacity and heat-rate improvements that expand available output.
- Portfolio Additions for Resource Adequacy– Projects to improve peak capacity deficits and planning reserve margin shortfalls.

[110] PGE/400, Ferchland-Barrow-Jose/26-27.

Transmission and generation investments (assets) that PGE would <u>not</u> define as growth-related are all other transmission and generation investments including:

- End-of-life replacements (like-for-like).
- Corrective maintenance or reliability repairs.
- Generator interconnection upgrades (unless it also serves load growth as well).
- Policy-driven clean energy replacements (unless it serves incremental load growth).

For projects with both growth and non-growth elements, PGE proposes classifying the investment based on the primary driver of the project. For example, the project would be classified as growth-related if, except for the need to serve new or incremental load, the work would not be required at this time and scope. Conversely, a project is non-growth related if it fails this test.[111] Because PGE already has a consistent, straightforward, objective approach to determining and categorizing growth, PGE respectfully requests that the Commission approve PGE's definition of growth-related investments (assets) as described above and in testimony.[112]

**d. What changes need to be made to PGE's Peak Growth Modifier before assigning costs related to growth?**

***The PGM Proposed Will Ensure Customers Pay Their Just and Reasonable Share***

The Commission should find that no additional changes need to be made to PGE's proposed PGM before assigning costs related to growth assets.[113] PGE's proposed PGM allows for customer classes that are immediately causing the need for increased investments to pay for them, while also recognizing that longer term, these investments benefit all customers and that it is appropriate for customer classes that benefit from the investments to pay a reasonable share of

[111] PGE/400, Ferchland-Barrow-Jose/27.
[112] PGE/400, Ferchland-Barrow-Jose/25-27.
[113] PGE/100, Ferchland-Barrow/23.

their cost over the life of the asset.[114] It appears that there is general alignment between Staff, CUB, and PGE that new load growth (and in particular large data centers) should directly bear the costs they cause, and other customer classes should not subsidize new load growth.[115] PGE's proposed PGM supports these goals. Once paired with the EGM as discussed in Section 16, this new approach to cost allocation will result in growth paying for growth.

The overarching principle of cost allocation is to allocate costs to the customer classes causing and benefiting from costs and avoid any customer class subsidizing another customer class. PGE's proposed PGM allows for classes that are immediately causing the need for costs to pay for them, while recognizing that, in the longer term, system assets benefit all customers.

**e. Are there any other issues with the PGM?**

***The Commission Should Reject Other Proposed Modifications to the PGM***

PGE's proposed PGM appropriately balances the fairness of cost allocation with system use and infrastructure realities and already accounts for weather-related impact. The Commission should find that PGE's PGM does not need additional modifications.

## 15. Should the Commission direct PGE to complete a "but for" analysis in its next CEP/IRP?

***A But-For Analysis Is Not Warranted***

Certain parties have suggested that a "but for" analysis based on PGE's IRP/CEP process be required to provide a check on the reasonableness of the generation marginal cost study, as well as to give stakeholders an understanding of the impact of large load customers on our generation and transmission planning decisions.

---

[114] PGE/200, Ferchland-Barrow/8-9.
[115] PGE/200, Ferchland-Barrow/8-9.

The Commission should reject this proposal because this issue is outside the scope of this docket. In addition, PGE does not agree that analyses conducted as part of the IRP process should be used to determine rates. The IRP's purpose is to identify a least-cost, least-risk portfolio of resources to meet system-wide reliability needs, which is distinct from the but-for analysis intended for ratemaking which requires isolating the incremental impacts of a specific customer class and is, by definition, inconsistent with the system-level focus of the IRP.[116]

Although PGE has not yet conducted this analysis, PGE is actively evaluating whether and how a "but for" analysis could be incorporated into the 2026 IRP/CEP, where planning assumptions, scenarios, and stakeholder engagement are expressly designed to support that type of evaluation.[117] It is therefore premature and unreasonable to require this type of analysis as part of this proceeding.

**16. Should the allocation of net variable power cost be updated and if so, how?**

***The Net Variable Power Cost (NVPC) Should Be Updated***

There are two key parts that combine to measure the system usage occurring across the customer classes: CP and load. In order to measure proportional growth in the system, both the PGM (which factors contribute to system growth through measurement of class contribution to CP) and the EGM (which measures load growth contribution by class), must be used. Taken together, this resulting total growth modifier, when incorporated into cost allocation, ensures that growth pays for growth in a comprehensive manner. The load measurements and cost allocation are a component of NVPC, which are adjusted yearly through PGE's Annual Update Tariff (AUT). PGE requests that the Commission approve a discrete adjustment to how NVPC is

[116] PGE/400, Ferchland-Barrow-Jose/27; PGE/200, Ferchland-Barrow/13.
[117] PGE/400, Ferchland–Barrow-Jose/28.

calculated so that it will include a measurement of increased load growth forecast per customer class to allow the additional costs for load growth to be proportionally assigned by customer class responsible for that load growth. This adjustment, referred to as the EGM, couples with the PGM to enable growth paying for growth.

By incorporating load growth into the calculation, increases in load impact investments in fixed generation or transmission assets as well as new power purchase agreements or market purchases for energy and capacity will be accounted for. These costs are included in prices within NVPC, which are updated every year through PGE's AUT filing.

Using 2025 as the baseline, PGE calculated revenues based on 2025 customer usage and prices, then projected 2026 usage at the same prices. The resulting difference—approximately $40.8 million—represents additional revenue driven solely by higher usage. This revenue growth, allocated by customer class, resets the starting point for each class's price change. To assess related cost impacts, PGE used the final 2025 AUT model with the 2025 load vintage, producing a NVPC of about $968.1 million. Substituting the 2026 load vintage into the same model yielded an NVPC of approximately $1,021.4 million, an increase of $53.2 million. This indicates that load-driven revenue growth of $40.8 million does not fully offset the corresponding rise in power costs driven by growth, leaving roughly $12.4 million of costs that are not being spread based on growth.[118]

Thus, we propose a simple adjustment that allocates these additional costs for load growth to each customer class based on their proportionate share of the increase in load from one year to the next, in this docket that would be from 2025 and 2026.

[118] PGE/200, Ferchland-Barrow/16.

Including the EGM and updating NVPC aligns with PGE's fundamental approach in this docket that growth pays for growth. This proposed re-allocation of the additional cost of load growth across customer classes drives costs to those causing them and creates more equitable customer allocations. Without reallocation, an important aspect of growth costs will not be paid for by the customer class responsible for them.

**17. Should the Commission find that direct assignment to a customer class is an appropriate method for assigning the costs of assets, either transmission or fixed generation?**

***Direct Assignment of Transmission and Fixed Generation Should Be Rejected Because the System Is Networked and Integrated and Serves All Customers***

The Commission should reject direct assignment of transmission or fixed generation to a customer class in this docket because, as proposed by other parties in this docket, it contravenes regulatory fairness and is not reflective of system design or functionality. Transmission and grid-connected generation resources are network system assets intended to serve all customers. They do not benefit only one customer or customer class, and thus assigning costs directly would not be a fair allocation of cost. Rather, direct assignment is akin to pushing the cost of a shared system onto a subset of the customers.

Direct assignment does not reflect the physical reality of how the system operates nor the regulatory principles of cost causation and benefit distribution. Generation resources are planned, operated, and dispatched on a system-wide basis and provide shared benefits across all customer classes. PGE's transmission facilities are planned and operated as part of an integrated, networked system and they provide reliability, operational flexibility, and contingency support that benefit the broader system and all customer classes. For these reasons, allocation of transmission and fixed generation should occur based on marginal cost, not direct assignment.[119] Further, PGE's systems do not support individual tracking of all individually assigned investments, depreciation, and cost of removal.[120] Finally, direct assignment would result in double-charging to data centers and large load customers through the PGM because, as discussed in Sections 8-14, these customers would be already paying a proportionately higher amount for growth-related assets that are associated with growth of other customer classes. If some transmission and generation assets are directly assigned to the data center class, then other transmission and generation assets must be directly assigned away from the data center class to avoid double-charging or applying two inconsistent cost allocation methods in a discriminatory fashion.

**a. Direct Assignment is Inappropriate for Generation Assets**

PGE agrees with Staff's position that direct assignment is not appropriate for generation assets. Generation resources are planned, operated, and dispatched on a system-wide basis and provide shared benefits across all customer classes.[121] For that reason, PGE continues to support allocations based on marginal cost, rather than direct assignment, as the appropriate ratemaking construct.[122]

As previously discussed, PGE asks that the Commission adopt an approach that initially allocates the costs of generation assets driven by growth proportionately to the customer classes responsible for that growth. If a data center customer prefers a specific resource or seeks to accelerate its interconnection to the system, special contracting—under which the customer

[119] PGE/400, Ferchland-Barrow-Jose/17, 18.
[120] PGE/100, Ferchland-Barrow/27-28.
[121] PGE/400, Ferchland-Barrow-Jose/17.
[122] *Id.*

directly funds the resource through a contract—is an appropriate and acceptable approach (discussed further in Section 44-46).

### b. Direct Assignment is Inappropriate for Transmission Assets

PGE requests that the Commission decline to adopt situs-based assignment of local transmission assets as proposed by certain parties. As discussed in PGE's testimony, transmission facilities—regardless of physical location—are planned and operated as part of an integrated, networked system. Even facilities that may appear "local" provide reliability, operational flexibility, and contingency support that benefit the broader system and all customer classes.[123] Assigning such assets on a situs basis risks overstating the causal relationship between individual loads and specific facilities, while understating their system-wide value and benefits to other customers.[124]

Additionally, it would not be appropriate to adopt a direct assignment framework that assigns transmission assets only to data center customers. If applied consistently as they should, such proposals of direct assignment will lead to directly assigning assets across PGE's entire transmission and distribution system.[125] This would be an incredibly burdensome, if not unachievable task, of which the impacts are not known.[126] And it is unclear what the overall result would be for customers of the adoption of a direct assignment framework. For example, industrial and commercial customers could reasonably argue for direct assignment of any transmission or distribution assets installed to serve residential customers. For these reasons,

[123] PGE/400, Ferchland-Barrow-Jose/18-19.
[124] PGE/400, Ferchland-Barrow-Jose/18-19.
[125] PGE/400, Ferchland-Barrow-Jose/19.
[126] *Id.*

PGE requests that the Commission approve the use of the PGM for transmission costs without carving out locally sited facilities for direct assignment to the data center customer class.[127]

**i. PGE's transmission system is an integrated system**

Transmission systems are network system assets intended to serve all customers. Given the integrated and networked nature of PGE's transmission system, direct assignment of transmission assets to specific customer classes is neither practical nor appropriate.[128]

Transmission facilities are planned, designed, and operated to support system wide reliability, flexibility, and contingency needs, and their benefits are not confined to discrete customers or locations. Because all of PGE's transmission lines are networked, there is a two-way flow, and a greater ability to re-route power so even localized transmission lines can have a positive impact on the customers around them.[129] PGE plans its system so that the loss of a transmission line due to a tree falling into the line or a lightning strike will not cause an outage because power will flow through another transmission line. Since the transmission lines benefit all customers, it does not make sense to directly assign the cost to a customer because the system cannot similarly directly assign the benefit to that customer and keep others from using that benefit – the cost would be borne by one, but the power would flow to others.

**ii. Transmission development has a variety of causes**

By way of background, PGE's regional transmission system is aging and has not experienced many significant upgrades in years. More than 4,800 miles of high voltage transmission lines were erected from 1960 to 1990 by the Bonneville Power Administration, but

[127] PGE/400, Ferchland-Barrow-Jose/19.
[128] PGE/400, Ferchland-Barrow-Jose/17-20.
[129] PGE/400, Ferchland-Barrow-Jose/20.

that rate of construction tapered in the following years.[130] As the system pivots to clean energy, previously unconstrained lines are becoming constrained, and system upgrades are required regardless of impending data center loads.[131] Data centers are not the only customer class triggering transmission upgrades—they are only one of many causing transmission system upgrades. The need for clean energy, electrification, and system constraints based on changes to flow can trigger transmission system upgrades, as can large new residential developments, such as the ones occurring in Happy Valley and off Scholls Ferry Road in the southwest Portland metropolitan area.

For example, the Hillsboro Reliability Project (HRP) was a project built to serve both residential and large load customers.[132] Parties have focused on the Evergreen substation work that occurred as a part of the HRP, but it was not the only work completed as a part of the project. While it is true that Evergreen was 59% of the total HRP project cost for both transmission and distribution, both Orenco (serving largely residential customers and some commercial customers) and Brookwood (serving a mix of residential, commercial, and industrial customers), comprised 41% of the costs and serve customer classes that are neither data centers nor large industrial load.[133]

These examples demonstrate that it is not simple to designate a transmission project as being caused by one customer class. In PGE's existing and forecasted system, it is difficult to point to a singular customer class as the driver and the sole beneficiary of a transmission system upgrade. Though certain customers may help to drive a system upgrade, they are not the only beneficiaries of that upgrade because of how our transmission system is integrated and any

[130] PGE/400, Ferchland-Barrow-Jose/19.
[131] *Id.*
[132] PGE/400, Ferchland-Barrow-Jose/20.
[133] PGE/400, Ferchland-Barrow-Jose/20-22.

upgrades to the system generally benefit all customer classes.[134] In the future, there may be instances where transmission facilities are built for the data center class in such a way that the transmission facility exclusively serves the data center class. In those instances, it may be appropriate to directly assign for retail ratemaking purposes the cost of the transmission facility to the data center class because it is operating in a distinctly different manner than transmission facilities currently do in PGE's system. It is only in this type of instance that direct assignment for retail ratemaking purposes is appropriate and feasible.

#### iii. Direct assignment is not workable from a ratemaking perspective

Attempting to directly assign transmission assets would significantly complicate ratemaking by requiring case-by-case determinations of the primary driver and beneficiary of each project. That approach would introduce substantial administrative burden, increase litigation risk, and undermine regulatory efficiency, as virtually every transmission investment would become subject to dispute. PGE's PGM provides a more workable and principled alternative.[135] As discussed earlier in Section 14, PGM allocates transmission costs based on each customer class's contribution to system peak growth, which reasonably reflects cost causation without requiring artificial distinctions among individual facilities. This approach appropriately recognizes that growth-driven investments are made to support the system as a whole and allows costs to be allocated in a manner that is both equitable and administrable over time.[136]

It is not appropriate to simply isolate costs of a single asset and then apply growth-related percentages that are calculated across all classes causing load growth. Growth percentages

[134] PGE/400, Ferchland-Barrow-Jose/20, 22.
[135] PGE/400, Ferchland-Barrow-Jose/22.
[136] PGE/400, Ferchland–Barrow-Jose/17-23.

calculated across all classes are meaningful only when applied to the total costs of all growth-related assets. Applying holistic percentages to individual projects is a misapplication that creates confusion for all. It is an illustration of the fallacy of division which is when someone wrongly assumes that what is true of the whole group must be true of each part or member of a group (for example, one cannot say because the car is fast, its muffler is fast). Put another way, if residential customers account for 28% of growth overall, it does not mean that PGE uses 28% of each growth asset to service residential customers. The growth percentages are determined across all classes and applied to the group of growth assets. It is inappropriate to focus on one asset or project and apply the growth percentages to that specific asset or project. For example, if members of the residential class assert that they are paying a portion of an asset primarily serving the data center class, then members of the data center class could also claim that they are paying even more for a growth asset that predominantly serves residential customers. Both assertions are wrong: with transmission, it is a shared resource.

**18. If costs are directly assigned, is this permanent or is this subject to revision at a later date?**

***Direct Assignment, if Any, Should Be Subject to Immediate Reconsideration Because the Impact Will Be Across All Customer Classes***

As discussed in response to Issue 14, PGE respectfully requests that the Commission decline to require direct assignment in this docket.[137] If the Commission determines that direct assignment in some instances is appropriate, it should not be permanent but should be reassessed during subsequent rate proceedings to determine whether other customer classes are benefiting from the asset and investment and whether they should pay a reasonable portion of the cost.

[137] PGE/400, Ferchland-Barrow-Jose/17, 18; PGE/100, Ferchland-Barrow/27-28.

Additionally, should the Commission order direct assignment to the Schedule 96 customers it should apply whatever principles are used to determine when direct assignment is appropriate to all PGE assets and investments to determine if other assets and investments should be directly assigned to other customer classes.[138]

If one set of customers seek to push all the cost of shared system costs onto one customer class, there is no reason other customer classes will not make the same type of arguments for other system resources that are driven by other customer classes. For example, distribution costs in urban areas undoubtedly are more associated with residential customers than industrial or data center customers. If the cost of network upgrades that benefit and serve all customers are allocated exclusively to large data centers, then data centers could argue persuasively that the cost of distribution system should be exclusively assigned to residential customers.[139] The outcome of such fragmentation of the network is uncertain given that the arguments in favor of such a misguided approach go both ways and will not stop with attempts in this context to assign all such grid improvement costs to a large data center customer class. Finally, the assumption underlying these arguments for fragmentation is unfounded: loads for residential customers are growing and contributing to peak growth.[140] For these reasons, if the decision is made to directly assign during this docket, it should be subject to immediate review.

---

[138] *See generally*, PGE/400, Ferchland-Barrow-Jose/19.
[139] PGE/400, Ferchland-Barrow-Jose/19.
[140] PGE/100, Ferchland-Barrow/27-28.

## 19. Should the Commission direct assign the costs of the Shute and Evergreen substations to Schedule 96 or Schedule 90 and 96?

***Like All Other Substations, Shute and Evergreen Substation Should Not Be Directly Assigned***

As the reasons that direct assignment is not appropriate as discussed above in Section 17 and 18 are the same reasons that direct assignment for the Shute or Evergreen substations would not be appropriate, the Commission should not order the direct assignment of the Shute or Evergreen substations costs to Schedule 90 and/or 96.[141]

## 20. Do the proposals put forth by PGE or any other party result in the double counting of costs and, if so, which ones?

***PGE's Proposals Ensure Costs Are Correctly Allocated and Not Double-Counted***

PGE's proposal ensures that costs are correctly allocated and not double-counted.[142] By creating a structure for allocating marginal cost so that growth pays for growth in a comprehensive framework of minimum demand charges, exit fees, and Make-Whole provisions, our proposal has sufficient safeguards without adding duplicative charges. For example, during this case, a party proposed that exit fees should include the full book charge for an abandoned distribution asset in addition to a minimum demand charge for the remainder of the contract length. PGE cannot support this because the minimum demand charge paid prior to exit is partial payment towards the book value of the distribution asset. Charging the book value upon exit would result in the double-charging of part of the costs.[143] The same double-charging might

[141] PGE/400, Ferchland-Barrow-Jose/17, 18; PGE/100, Ferchland-Barrow/27-28,
[142] PGE/200, Ferchland-Barrow/10.
[143] PGE/300, Fagan-Frayer/34.

occur in instances where the customer elected CIAC for distribution. If CIAC has been paid, the total amount paid to CIAC should be credited to the net book value of the cost of work based on the CIAC deposit left at the time of exit, which will reduce the exit fee.[144]

In addition, PGE believes that the creation of Schedule 96 should result in the distribution revenue requirement being allocated to the data center customer class and that the distribution revenue requirement should not be spread to other classes. This is consistent with how distribution revenue requirements are handled across customer classes and this approach will enable customers within the class to pay incremental monthly distribution costs and, when tied with the minimum distribution demands and the proposed changes to the distribution marginal cost, ensure that operational and maintenance (O&M) costs attributed to Schedule 96 are paid in full by data center customers and do not have under collection.[145] This approach also prevents Schedule 96 O&M from being spread to other customer classes.[146]

### 21. Should data centers be charged the marginal cost of transmission?

#### *Data Centers Should Pay Increased Costs Through The PGM, Not Through the Marginal Cost of Transmission Proposed by Other Parties in this Proceeding*

PGE respectfully requests that the Commission order that transmission costs be allocated based on PGE's proposed PGM, which reflects charging customers for the cost of transmission based on marginal cost principles.[147] Other parties have proposed under the rubric of "marginal costs" directly assigning the cost of transmission assets to a specific customer class. That is, they propose that the data center class should pay the marginal cost of

---

[144] PGE/200, Ferchland-Barrow/31.
[145] PGE/200, Ferchland-Barrow/24, 31.
[146] *Id*.
[147] PGE/400, Ferchland-Barrow-Jose/18, 19.

transmission. The Commission should reject the idea that data centers should be charged the marginal cost of transmission because this would mean the direct assignment of transmission costs.[148] As discussed in Section 17 and 18, transmission facilities - regardless of physical location - are planned and operated as part of an integrated, networked system. As discussed in testimony and this brief, even transmission facilities that appear local provide reliability, operational flexibility, and contingency support that benefit the broader system and all customer classes. The direct assignment of a transmission asset on a situs basis risks overstating the causal relationship between individual loads and specific facilities while understating their system-wide value and benefits to other customers.[149] For the reasons previously discussed, the concept of assigning marginal cost for transmission should be rejected.

**22. Should the Commission direct PGE to study the cost allocation approaches that the Regulatory Assistance Project (RAP) proposes compared to the 4-CP and 12-CP approaches? (CUB/300 Jenks/13-16).**

***PGE's Proposal Makes Sense and Additional Study is Not Warranted at This Time***

PGE's proposal to update marginal cost allocation and apply requirements to protect customers while ensuring growth benefits the system is thoughtful and sensible and the result of iterative evaluation with multiple stakeholders providing feedback throughout this docket. In this docket PGE has reviewed options suggested by CUB to look at alternatives to the traditional 4-CP and 12 CP allocations. PGE found that analyzing the top 100 hours and top 5% of hours with the highest system load in 2024 resulted in higher allocations to residential customers.[150] PGE's

[148] PGE/400, Ferchland-Barrow-Jose/19.
[149] PGE/400, Ferchland-Barrow-Jose/18, 19.
[150] PGE/400, Ferchland-Barrow-Jose/23.

proposal and recommendation to approve the PGM and other changes in this instant docket are supported by the record evidence and additional study is not warranted at this time. Further, any additional study will result in a delay of marginal cost allocation that will benefit customers.

PGE's proposal is not meant to be permanent. Indeed, just as the energy sector does not stay static, PGE anticipates that future years may bring new challenges and opportunities. Looking ahead, as large data center loads grow, PGE expects the residential class contribution to system peaks to decrease and Schedule 96 contribution to increase significantly. While PGE's request is that the Commission approve our proposal, PGE will continue to explore and assess future alternative allocation methodologies that could improve alignment between cost causation and allocation, as we have in this docket.[151] Thus, while it is not warranted to require additional study of another proposal at this time, PGE will be engaged in future reviews were appropriate.

**23. Are there any other topics related to marginal cost and cost allocation that a party would like to address?**

***The PGM Should Be Adopted***

PGE's marginal cost study, cost allocation, and PGM as proposed should be adopted as soon as practicable because it enables PGE to allocate proportional costs to the customer classes driving growth and it balances the fairness of cost allocation with system use and infrastructure realities. Additional changes to PGE's proposal are not warranted at this time.

## E. Rule I

PGE proposes changes to Rule I to add additional protections to ensure that data center and large load customers' contractual terms are sufficient to mitigate the risk other customers from potential rate exposure caused by stranded assets and revenue loss if a large load customer

---

[151] PGE/400, Ferchland-Barrow-Jose/24.

exits service early. PGE’s proposed minimum contract length, credit requirements, minimum demand charges, capacity deposits, exceedance penalties, exit fees, and Make Whole provisions layer together to comprehensively reduce risk. Prior to entering into a customer service contract under Rule I, PGE will review available capital and existing plans to ensure that the level of capital required for each project is incorporated within PGE's long range plan.

## 24. What should the minimum contract term length and minimum contract renewal term length be for Large Load Customer Agreements (LLCA) under Rule I?

### *The Minimum Contract Length for Large Load Customers (LLCA) Should Be 10 Years, With a Three Year Renewal Term*

The Commission should approve a minimum contract length of 10 years for the LLCA under Rule I, which is consistent with the POWER Act. This modifies the current tariff LLCA length from a minimum of eight years. In addition, the Commission should approve an automatic three-year renewal following the conclusion of the initial contract period.[152] With this automatic three-year automatic renewal, PGE proposes a minimum 36-month notice period.

The Commission should not adopt proposals scaling contract periods based upon the size of the data center. Requiring data centers to sign long initial contracts with longer renewal periods takes away a level of flexibility to sign different length contracts that match their operations. PGE’s proposal for ten year minimum initial terms and automatic three year minimum renewals strike a balance between allowing customers adequate flexibility and ensuring adequate planning and performance time for PGE. When coupled with the extensive protections discussed further below, including minimum demand charges, exit fees, and Make

[152] PGE/400, Ferchland-Barrow-Jose/42.

Whole provisions, the potential risks associated with shorter contracts are mitigated. The primary difference in different contract length minimums is the Make Whole Provision, as longer contract terms could subject customers to larger financial commitments but the exit fees do not change, so requiring longer contracting periods does not ensure any additional customer protections because PGE's agreements are evergreen and customers cannot reduce their contracted capacity unless mutually acceptable.[153] PGE proposes that the minimum contract term length be ten years for LLCA customers, which is two years longer than the current eight year initial contract period. This recommendation is consistent with the POWER Act, which requires a contract to be for a duration of ten years.[154] After the initial ten years, an automatic three year renewal clause takes effect. This renewal clause requires extensive advance notice to break (that is, customers must alert PGE at least three years in advance to break from the contract before the automatic renewal clause is in effect, rolling their initial contract forward to a thirteen, then a sixteen and then a nineteen year contract and continuing forward, unless they take action to end it pursuant to renewal terms). LLCA customers will be able to sign an initial contract term length up to thirty years, if they prefer, and they may also request longer renewal periods if they prefer.

By adopting a ten year minimum initial term plus strict rolling renewal requirement, PGE's proposal allows customers the planning flexibility that matches their operations but has sufficient protection against stranded assets by requiring minimum demand charges, exit fees, and Make-Whole provisions. The contractual language requires customers and PGE to stay with contracted capacity unless mutually acceptable, which mitigates against a customer or PGE changing the capacity terms unilaterally mid-contract. Requiring a longer period of initial contract length would not increase protections for other customer classes in a meaningful way

[153] PGE/400, Ferchland-Barrow-Jose/42.
[154] ORS § 757.295 (1)(B)(A)(ii).

and instead is likely to deter prospective LLCA customers from becoming cost-of-service customers with PGE, which will ultimately result in less benefits to all of PGE's customers and the system. As proposed, PGE's contractual terms provide LLCA customers with reasonable planning options that come with stringent financial requirements that adequately protect all customers if the LLCA customers exit service or decide not to renew at some point in the future.

**25. What should the requirements for credit worthiness be and what forms of credit should be acceptable?**

***PGE's Proposal for Creditworthiness and Credit Forms Should Be Approved***

PGE's proposal includes the maintenance of the creditworthiness requirements for large load service contracts[155] set in UE 430, which is as follows:

> (i) the senior unsecured long term debt of such Person has a rating of A- or higher by Standard & Poor's or Fitch, A (low) or higher by DBRS, or A3 or higher by Moody's Investor Services, Inc.; provided that if a Person is rated by multiple credit rating agencies, the Person will be deemed to satisfy the Creditworthiness Requirements only if at least two of the foregoing standards are met, *or*
>
> (ii) if there is no such rating of the Person's senior unsecured long-term debt, the Person has an equivalent rating as determined by PGE through its standard internal process review.

In addition, PGE believes that additional forms of collateral should be allowed if they do not meet PGE's credit support requirements or provide a guaranty issued by a Person that satisfies the Creditworthiness Requirements.[156] These additional forms of collateral could include, but are

[155] PGE/400, Ferchland-Barrow-Jose/45.
[156] PGE/200, Ferchland-Barrow/28; PGE/407 at 20.

not limited to, letter of credit, surety bonds or cash. Further, in instances where the customer stays on PGE's system for a longer period of time, PGE believes that the collateral could be reduced. This reduction in collateral, which would occur as the customer progresses through their contract, mirrors the reduction in financial exposure as the revenue requirements decrease for the assets constructed to serve the customer. Reducing collateral over time will free up additional capital for the customer, but the incentives to remain in the contract will still be strong (exit fees, Make Whole provisions, and the remainder of the collateral as applicable).

**a. Does PGE need to explicitly list credit requirement standards in its tariff? Further, can PGE have different credit requirements for different customers based on perceived risk?**

***PGE Should Not List Its Credit Requirement Standards in Its Tariff***

PGE respectfully requests that the Commission decline to require that the creditworthiness requirements be listed in the tariff because, while it is critical to have high standards for credit worthiness such as PGE has, listing the specific detailed aspects for credit worthiness is unnecessarily prescriptive and limiting. Instead, PGE supports a general standard that applies to all customers.[157] PGE recommends allowing additional forms of permitted collateral in Rule I, such as surety bonds and cash deposits. PGE will continue to approach creditworthiness requirements with an open mind to a tiered approach and is open to adjusting the creditworthiness requirement further if needed and would do so in a manner to protect PGE and its customers from risk.

[157] PGE/200, Ferchland-Barrow/28.

## 26. Should there be a minimum demand charge and what should its terms be for?

***The Commission Should Approve Minimum Demand Charges.***

As an important protection to guard against cost-shifting, PGE respectfully requests that Commission approve a minimum demand charge for generation, transmission, and distribution within the LLCA.[158] PGE's proposal strikes the appropriate framework of setting a sufficiently high minimum that would encourage customers to be realistic about how much energy they needed and provide adequate safeguards for existing customers from speculative load that did not manifest, while not being unfairly punitive and placing unfair burdens on large load customers. These minimums are not meant to fully guarantee recovery of all these costs. An 80% minimum strikes an appropriate balance when coupled with the rest of PGE's proposed framework.[159]

PGE's proposal strikes a more equitable balance than the ones proposed by other parties. In testimony, PGE provided a survey of various utility demand charges which shows the reasonableness of PGE's approach. Consumers Energy, Evergy, and Indiana Michigan Power all have 80% minimums. American Electric Power in Ohio and Dominion both have 85% minimums on transmission demand; however, Dominion only has a 60% minimum for generation demand. Of the utilities that have established minimums, there is only one that has a 90% minimum, Kentucky Power, whereas the others vary between 80% and 85%. Of note, Kentucky Power's large load tariff is only for customers with loads of at least 150 MW, which is substantially larger than our 20 MW threshold and, therefore, should not be used for comparison.

---

[158] PGE/400, Ferchland-Barrow-Jose/5.
[159] PGE/400, Ferchland-Barrow-Jose/37.

Setting PGE's minimum to 90% would place PGE at the highest end of the spectrum, which would be unnecessarily onerous given the 20 MW load threshold.

PGE's proposed 80% minimum, paired with the rest of the framework and contract provisions, provide proper protections for existing customers while serving new customers and appropriately allocating the cost of service to them. These new customers provide an increased base to spread infrastructure costs that would be needed, regardless of data center load, such as costs associated with wildfire mitigation, system upgrades, and the clean energy transition.[160]

The goal behind PGE's proposal for 80% for a minimum demand charge for generation, transmission, and distribution is to set a sufficiently high minimum that would encourage customers to be realistic about how much energy they needed and provide adequate safeguards for existing customers from speculative load that did not manifest, while not being unfairly punitive and placing unfair burdens on large load customers. These minimums are not meant to fully guarantee recovery of all these costs. An 80% minimum strikes an appropriate balance between all the stated goals when coupled with the rest of PGE's proposed framework.[161]

Setting rates to an excessively high level for large load data centers carries real risks: it could violate the Commission's standard for fair, just and reasonable rates; and it may deter data centers from locating in the state, ultimately reducing the customer base for spreading required infrastructure costs, thereby putting upward pressure on other customers' rates. No parties have provided evidence for their proposals to show that a threshold above 80% is necessary to ensure that large load data centers pay for their cost of service and prevent unwarranted cost shifting.[162]

[160] PGE/400, Ferchland-Barrow-Jose/38.
[161] PGE/400, Ferchland-Barrow-Jose/37.
[162] PGE/200, Ferchland-Barrow/22.

PGE's proposal of 80% strikes a balance of all these goals while maintaining a fair and competitive environment for new large load customers. A minimum beyond 80% would be inconsistent with minimums set in other jurisdictions. While it is important to protect existing cost of service customers from stranded asset risk, minimums must be set at reasonable levels.

**a. Minimum Generation Demand (MGD)?**

***The Minimum Generation Demand (MGD) Should Be 80%.***

As stated above, PGE respectfully requests that the Commission approve a minimum generation demand requirement equivalent to 80% of contracted allocated system capacity. The minimum generation demand charge serves to mitigate the near-term risk of under-utilized generation assets that were procured to serve a new large load customer that is not utilizing their allocated capacity.[163]

**b. The Minimum Transmission Demand (MTD)?**

***Minimum Transmission Demand (MTD) Should Be 80%.***

The Commission should approve a minimum transmission demand requirement equivalent to 80% of contracted allocated system capacity, which maintains the standard adopted in UE 430. This percentage strikes a balance between the need for cost recovery with the fact that transmission is a system resource; this standard is also aligned with the broader regulatory landscape.[164]

[163] PGE/100, Ferchland-Barrow/37.
[164] PGE/100, Ferchland-Barrow/34.

### c. Minimum Distribution Demand (MDD)?

***The Minimum Distribution Demand (MDD) Should Be 80%.***

The Commission should approve a minimum distribution demand requirement equivalent to 80% of their contracted allocated system capacity.[165] This is an update from an earlier flat billed distribution demand. The earlier flat-billed distribution demand was appropriate prior to the creation of Schedule 96. Now with a new, distinct schedule, a minimum 80% distribution demand will address Staff's concern about under-recovery of distribution O&M costs and better meet the desire for a simple and standard experience for customers.[166] The minimum 80% distribution demand provides enhanced protection for the entirety of the contract, initial term plus renewals, while the flat-billed distribution demand typically transitions to actuals following the initial term.[167]

### 27. If the MDD is not adopted, should customers continue to be charged a flat billed demand that generates revenue equal to the revenue requirement of their incremental distribution assets?

***If the MDD is rejected, Customers Should Continue to Pay a Flat-Billed Demand Charge, Even Though it Will Result in Undercounting Costs in Comparison to the Preferred MDD***

If the recommended MDD is rejected, the Commission should maintain a flat billed distribution demand charge. A flat billed demand charge will not address Staff's concern about under-recovery for distribution O&M costs and it will result in data center and large load customers' bills being less responsive to changes in distribution revenue requirements for large

[165] PGE/200, Ferchland-Barrow/23.
[166] PGE/200, Ferchland-Barrow/24.
[167] *See generally* PGE/200, Ferchland-Barrow/23.

customers (because they will see a flat amount, not a variable one that reflects the revenue requirement).[168]

PGE proposes replacing the flat billed distribution demand with the same 80% minimum utilized for generation and transmission. When PGE first proposed the flat billed distribution demand in UE 430, data center customers did not have their own rate schedule, and a flat-billed distribution demand struck an appropriate balance at the time. With the expanded scope of this docket, PGE now has the opportunity to streamline the customer experience to a consistent billed demand for transmission, distribution, and fixed generation each month.

In addition to the streamlined experience for customers, PGE's proposed approach will address Staff's concern about under-recovery of distribution O&M costs. Because demand is no longer held at a flat amount, customer bills will be more responsive to changes in the distribution revenue requirements for large customers.[169]

## 28. Should the LLCA permit PGE to charge a system capacity deposit and what terms should apply to system capacity deposit?

### *PGE Should Charge a System Capacity Deposit for LLCAs*

The Commission should continue its support of the current system capacity deposit application in the LLCA as approved in UE 430.[170] Specifically, the Commission should approve a cash deposit due at contract signing equal to two years of minimum transmission demand that is refundable. The Commission should approve the refund eligibility of the deposit to include meeting the Flexible Load Plan established in the LLCA and not being in arrears.[171]

[168] *Id.*
[169] PGE/200, Ferchland-Barrow/23-24.
[170] PGE/100, Ferchland-Barrow/35
[171] PGE/400, Ferchland-Barrow-Jose/43, 44.

PGE and the Coalition have similar proposals related to transmission demand for the system capacity deposit, the key difference being that PGE's proposal does not require the customer to meet their 80% requirement but does require the customer to meet their Flexible Load Plan. This requirement is sufficient and the addition of the 80% is not necessary as customers will be charged a minimum demand regardless of whether they meet their allocated capacity or not. The inclusion of the Make Whole Provision, as discussed in Section 30, provides additional protection against a contracted customer failing to show up for their energization. The system capacity deposit is not intended to be the full protective mechanism of the contract and should be considered as part of a complement of protections.[172]

**29. Should the LLCA and Minimum Load Agreement (MLA) permit PGE to charge an exceedance penalty when a customer exceeds their allocated system capacity, and if so, how should it be calculated, should there be a buffer, and should it be listed in the contract or tariff?**

***PGE's Proposed Exceedance Penalty Should Be Approved***

PGE recognizes the importance of a strong penalty to deter customers from poor planning that results in undue strain on the system, which will impact other customers. Thus, PGE respectfully requests that the Commission approve its proposed calculation for the transmission exceedance penalty as four-times the transmission rate multiplied by the actual demand minus the exceedance threshold per hour; this will be triggered if the customer exceeds their allocated and contracted for system capacity would serve as the threshold with no buffer approved.[173]

PGE designed the exceedance penalty rate to serve as a strong disincentive against customers exceeding their contracted load, especially during a period of high system utilization.

---

[172] PGE/400, Ferchland-Barrow-Jose/43.
[173] PGE/200, Ferchland-Barrow/24.

This is an important protection for all retail customers because if a customer exceeds their contracted load when the system is at full capacity, the system can become unstable and place it at increased risk of localized outages. Because the precise costs and operational consequences of such exceedances are difficult to quantify in advance, a clearly defined and firm penalty rate provides a necessary signal to encourage customers to remain within their contracted limits and helps safeguard system stability.[174]

The penalty proposed sufficiently encourages thoughtful load planning and does not require a buffer, which is no longer recommended by PGE.[175] A buffer is not recommended because allocated system capacity serves as the clear threshold without the buffer whereas a buffer simply discourages customers from close planning to right-size their load as there is a tolerance over and above their allocated system capacity.[176] As a result of removing the exceedance penalty buffer, the exceedance penalty would apply based on the Allocated System Capacity. With the removal of the buffer on the existing exceedance penalty, there is a proper balance of discouraging over-use without being needlessly punitive. The existing penalty provides sufficient incentive for customers to stay within their allocated capacity, and the addition of a generation penalty would be excessive.[177]

To go along with the transmission exceedance penalty, PGE is open to considering the 1.5 times generation exceedance penalty as proposed by several parties as exceeding allocated system capacity for generation also means that there is a need to procure additional energy on the market, which can be costly.[178]

---

[174] PGE/100, Ferchland-Barrow/35.
[175] PGE/400, Ferchland-Barrow-Jose/40.
[176] PGE/200, Ferchland-Barrow/24.
[177] *Id.*
[178] *See* PGE/400, Ferchland-Barrow-Jose/40.

PGE has proposed that the exceedance penalty, including when it is triggered and the method for calculating the penalty, appear in Rule I for transparency, and then to further detail the penalty and its precise parameters with reference to the LLCA in the schedule.

**30. Should the LLCA include a make whole provision and, if so, what should it be?**

***Make-Whole Provisions are an Important Safeguard***

One of the concerns presented with data centers and large load customers entering service is that the customers may then exit service before adequately paying for the investments made on their behalf, potentially resulting in stranded assets, the cost of which would need to be borne by the other customers in the system. It is important to mitigate the financial exposure caused by the possibility that data center customers and large load customers may terminate their long-term contracts before meeting their financial commitments. In UE 430, PGE adopted through Rule I an exit fee to make sure that other customers were protected against the stranded distribution asset risk from large load interconnection. In this docket, we are proposing to enhance those protections by adding a Make Whole provision which augments the exit fee and addresses lost transmission and generation demand changes for large load customers who exit during the term of their agreement.

In addition to the exit fees discussed further below, PGE recommends including a new Make Whole provision for Category 3 LLCA customers (the largest, and thus highest risk to the system if they exit early). The LLCA Make Whole provision should apply to any customer who leaves service during their contract term (initial or renewal). The Make Whole penalty would be the greater of three years of minimum transmission demand revenue <u>and</u> generation demand revenue, *or* minimum transmission demand <u>and</u> generation demand revenue for the remainder of their contract term.[179] As a result, customers who exit earlier in their contract term will face higher Make Whole penalties. The “smallest” Make Whole penalty a customer might pay for early exiting is three years of minimum transmission demand and generation demand revenue, which is a substantial amount of money and a significant deterrent. Three years is appropriate here because it is a reasonable amount of time necessary for PGE to find a replacement customer that can fill the revenue demand created by the exiting customer.

The Make Whole provision would apply during the initial contract term and renewal periods. Should any portion of generation or transmission be able to be reattributed to another customer, the customer paying the Make Whole would be eligible for a refund.[180] Category 2B customers would continue to pay the Exit Fee but would not be responsible for costs under the Make Whole provision.

**31. What exit fee should apply if a customer terminates or does not renew the contract?**

***PGE’s Exit Fees Should Be Approved Because They Establish the Right Balance***

In addition to the Make Whole provision, the Commission should approve PGE’s recommended exit fee as set forth herein because our recommended exit fees for LLCAs and MLAs strike an appropriate balance between ensuring that the customers remaining on the system are not unfairly impacted by an exiting large load and ensuring that provisions are not unduly burdensome on existing customers.[181] Unlike Make Whole penalties, which would only occur if a Category 3 LLCA customer exited early, PGE’s proposal includes exit fees that would

---

[179] PGE/200, Ferchland-Barrow/25-26.
[180] *Id.*
[181] PGE/400, Ferchland-Barrow-Jose/42.

apply to all LLCA and MLA customers. If the customer was a Category 3 LLCA customer, the customer would have both a Make Whole provision and an exit fee in their contract. As London Economics International recognized, PGE is proposing exit fees because exit fees are needed to prevent cost-shifting of system assets from one class to another.[182] Exit fees are tools to shield remaining customers in the system from the impact of additional expenses caused by the loss of the exiting customer in stranded assets and lost future revenue.

PGE recommends that for customers in an LLCA, the Commission should find that the exit fee should be equal to: the net book value of the Cost of the Work calculated as of the date that is three years after the date of termination or expiration of the LLCA, as determined by the PGE in accordance with generally accepted accounting principles; plus any additional costs reasonably incurred or owing by PGE in connection with winding up the construction work, including any costs of decommissioning and removal of the distribution facilities, net of salvage value as determined by PGE in its reasonable discretion, and costs incurred in connection with the cancellation of third-party contracts; plus an amount equal to three years of distribution charges at the then-current tariff rates for distribution and equal to either billed demand or actual demand (if there is no billed demand) as applicable to the customer at the time of termination or expiration of the LLCA.[183]

For customers in an MLA, the Commission should find that the exit fee should be equal to: the net book value of the Cost of the Work calculated as of the date of termination or expiration of the MLA, as determined by PGE in accordance with generally accepted accounting principles; plus any additional costs reasonably incurred or owing by PGE in connection with winding up the construction work, including any costs of decommissioning and removal of the

[182] PGE/300, Fagan-Frayer/14.
[183] PGE/407 at 20.

distribution facilities, net of salvage value as determined by the company in its reasonable discretion, and costs incurred in connection with the cancellation of third-party contracts.[184]

The exit fees proposed by PGE are strong and London Economics International found them to be at the high end in terms of protection for other customers in comparison with other jurisdictions.[185]

## 32. Should there be any refunds for the Exit Fee and a make whole provision? If so, how and when should this refund apply?

***Refunds to Exit Fees Are Appropriate in Certain Circumstances***

Notwithstanding the important safeguards that exit fees bring, PGE requests that the Commission allow a refund of the exit fee, in whole or in part, directly to the exiting customer if another customer assumes the exiting customer's capacity within three years.[186] Similarly, the Commission should also approve PGE's ability to refund the Make Whole penalty, in whole or in part, to the exiting customer if PGE can find another customer to execute a service agreement of the contracted transmission and/or generation.[187] Exiting customers will not be eligible for a refund of either exit fees or the Make Whole penalty if it takes more than three years to find a replacement customer. This is a reasonable balance between the additional costs and inherent risks associated with exiting customers and the potential for refund eligibility.[188] PGE is also open to AWEC's proposal to memorialize that PGE would not double-charge (collect an exit fee, fail to return the exit fee while simultaneously collecting from the replacement customer). If the new customer is found before three years, the applicable remaining Make Whole penalty and exit

[184] PGE/407 at 20.
[185] PGE/300, Fagan-Frayer/10.
[186] PGE/400, Ferchland-Barrow-Jose/42.
[187] PGE/400, Ferchland-Barrow-Jose/44.
[188] PGE/200, Ferchland-Barrow/25-26.

fee will be refunded, as applicable. After three years, during which PGE will have the ability to use the exit fees and Make Whole penalty to offset the corresponding lost revenue, the refund will not occur.[189]

## 33. How should the funds from exit fees and make whole provisions be applied?

### *Exit Fee and Make Whole Funds Should Be Applied to the Depreciated Asset Value and the Distribution Demand Revenue*

As discussed, exit fees and Make Whole penalties are recommended to protect all customers against cost-shifting, stranded assets, and lost revenue. PGE respectfully requests that the Commission continue to support that any exit fee funds be applied in two distinct ways: the depreciated asset value would buy down the asset to reduce revenue requirement and the distribution demand revenue (3-years for an LLCA; N/A for MLA) would be applied to distribution demand revenue for up to the three-year period from exiting.[190] PGE is open to considering the application of the revenues from the Make Whole penalty to the customer class impacted by the exiting customer, but as transmission and generation are system assets,[191] the overall system benefits would need to be factored into the proportional allocation of the penalty funds back to that customer class.

## 34. What should be the kilowatt threshold for the requirement to enter into the LLCA?

### *Customers Should Be Able to Enter a LLCA at or Above 20,000 kW*

PGE's recommendation, which PGE understands that other parties agree with, is that customers should be able to enter an LLCA at or above 20,000 kW. This demarcation reflects the

[189] PGE/400, Ferchland-Barrow-Jose/42; *see also* PGE/407.
[190] Dkt. UE 430, PGE/200, McFarland-Macfarlane, 17.
[191] PGE/400, Ferchland-Barrow-Jose /42.

POWER Act, which includes in the definition of "large energy use facility" facilities that use or are able to use the same amount.[192] Today, customers may enter a LLCA at 30,000 kW or higher. PGE believes that lowering this to 20,000 kW will enhance protections for all customers and increase options for prospective customers because LLCAs encompass a suite of provisions to mitigate against stranded assets and lost revenue while bringing options to prospective customers and these protections and options will now be applied to a larger group of customers.[193]

**35. If a customer with a large load service agreement opts for direct access, will the customer be responsible for MGD, MTD, and MDD and other costs (PGE/400, Ferchland-Barrow-Jose/46-47)?**

***Large Load Customers Opting for Direct Access Should Have Cost Responsibilities Commensurate With Other Large Load Customers***

For large customers opting for direct access under existing Direct Access structures (addressed separately in UM 2024), PGE remains the provider of last resort (POLR) and continues to hold system planning and reliability obligations even if load migrates off the system to go to direct access.[194] This creates asymmetric risk: if direct access load departs and later returns, PGE must be ready to serve that load without having retained commensurate cost recovery or planning certainty during the interim. Those risks can- but should not- ultimately be borne by remaining customers. As discussed below and further in Sections 44-46, special contracts avoid this dynamic by providing a more stable, predictable, and enforceable framework for serving large loads. They align customer responsibility with system impacts, support long-

[192] ORS § 757.292
[193] Parties anticipate filing a stipulation to this effect on or after February 4, 2026. This section is included in the Opening Brief for completeness as it appeared in the contested issues list and the position statement, but we expect the issues to be addressed only in connection with the stipulation.
[194] Dkt. UE 115, Order No. 01-777 at 39.

term planning, and protect non-participating customers from costs and reliability exposure, making them a more appropriate mechanism than expanding direct access for accommodating large, complex load growth.[195]

When taking a step back when considering the best durable, long-term solution to serve new large loads, the Commission must consider the importance of regional reliability. Reliability is a critical threshold condition that must be considered when establishing this framework.[196] Data shows that regional reliability is currently strained and is worsening.[197] PGE remains both the balancing authority and under some circumstances the POLR for electric service suppliers who fail to plan or procure.[198] PGE's obligations as the POLR is to reliably serve customers who return to cost-of-service from their electric service supplier, often with little notice.[199] As the BA, PGE maintains real-time system balance and provides ancillary services, among other requirements.

Ultimately, PGE expects that no matter what entities the Commission incentivizes the large load customers to procure electricity from (either electric service suppliers or PGE), PGE will be primarily responsible for the costs of reliability. This occurs because either (1) the Commission creates reasonable pathways for large load customers to be PGE customers directly

---

[195] PGE/400, Ferchland-Barrow-Jose/52-53.

[196] *See* Dkt. UE 102, Order 99-033 (January 27, 1999) (the Commission stating that Oregon Governor Kitzhaber's overriding objectives of restructuring and direct access was to "maintain the reliability, safety, and quality of electric service" and that the Commission is "guided by the principles" set out by Governor Kitzhaber); Dkt. UE 358, Order 20-002 at 8 (stating that the "ultimate and overriding obligation is to develop a framework that we are confident ensures reliability").

[197] *See Oregon Public Utility Commission, Special Public Meeting UM 2377 Investigation into Marginal Cost Study Treatment of Costs for Large Customers* at 50:30–52:00 (January 21, 2026); *see also* Dkt. UM 2404, Order 25-474 App. A. at 13–14 (stating there is "ongoing uncertainty about and challenges in meeting [resource adequacy] requirements"); *see also AWEC Petition for Investigation Into Long-Term Direct Access Programs,* Dkt. UM 2024, PGE/100 at Goodspeed-Ferchland/8-32 (May 2, 2025).

[198] Dkt. UE 115, Order No. 01-777 at 39; *see also* Oregon Public Utility Commission SB 978 Legislative Report at 52 (2018),

[199] Dkt. UE 115, Order No. 01-777 at 39; *see also* Dkt. UM 2024*,* PGE/100 at Goodspeed-Ferchland/12 (May 2, 2025).

in this docket, where PGE would maintain its own resource adequacy obligations; (2) the Commission approves proposed resource adequacy products, in which electric service suppliers have the option to purchase resource adequacy from PGE;[200] or (3) electric service suppliers do not schedule their energy delivery appropriately, in which PGE acts as the balancing authority, providing resource adequacy to electric service suppliers.[201] The Commission should consider the first option the most beneficial, because the Commission is able to shape the relationship between PGE and large load customers through close regulatory oversight. As Staff admitted during the proceeding, large load regulation is in its infancy and will require continued iteration.[202] Currently, option two is a proposal that lacks the scrutiny and details regarding cost allocation of resources that PGE would have to procure in order to provide a resource adequacy product, therefore, not providing similar regulatory safeguards as option one.[203] Additionally, option three is not within the Commission's jurisdiction, despite having real economic effects on PGE's cost-of-service customers. These are important considerations and obligations that must be considered to support the use of special contracts for new large loads, as discussed further in Section 44-46.

Consistent with preventing cost shifting and increased risk to the system, the Commission should find that a customer with an LLCA being served under direct access who is not a prior

[200] *See* Dkt. UM 2404, Order 25-474 App. A. at 13–14 (November 25, 2025) (discussing a proposed capacity backstop charge); *see also* Dkt. UM 2024, Exhibit Calpine Solutions/200, Higgins/3 (Jun. 25, 2025); Dkt. UM 2024, AWEC Position Statement at 7 (November 12, 2025).
[201] *See* Dkt. UE 358, Order 20-002 at 3 (Jan. 7, 2020); *see also* Dkt. UM 2024, PGE/100 at Goodspeed-Ferchland/20-21.
[202] Oregon Public Utility Commission, *Special Public Meeting UM 2377 Investigation into Marginal Cost Study Treatment of Costs for Large Customers* at 50:30–52:00 (January 21, 2026). https://oregonpuc.granicus.com/player/clip/1598?view_id=2&redirect=true (discussing how reevaluation is necessary as conditions change).
[203] Dkt. UM 2024, NIPPC Opening Br. at 36 (January 15, 2026) (stating "because the record is not fully developed on the design of a capacity backstop charge, NIPPC recommends that the Commission initiate further proceedings to develop an appropriately designed capacity backstop charge.")

cost-of-service customer should have the following cost responsibilities related to MGD, MTD, MDD, in addition to the charges and adjustments set forth in the applicable Direct Access schedule:

- Standard system capacity deposit, Exit Fee, and MDD per the tariff;
- No minimum generation demand in the LLCA served via direct access;
- Modified MTD that applies if a customer's usage is below the minimum transmission demand in the LLCA. The customer will be required to pay a transmission demand charge of the difference between actual usage and the minimum transmission demand; and,
- Applicable Direct Access transition adjustment charges.[204]

A customer with an LLCA that switches from cost-of-service to direct access should have the following costs responsibilities for MTD, MDD, and other costs, in addition to the charges and adjustments set forth in the applicable Direct Access schedules:

- Standard system capacity deposit, Exit Fee, and MDD per the tariff;
- Modified MTD that applies if a customer's usage is below the minimum transmission demand in the LLCA. The customer will be required to pay a transmission demand charge of the difference between actual usage and the minimum transmission demand before a customer went on direct access; and,
- Applicable direct access transition adjustment charges.[205]

PGE proposes the addition of a section to Rule I titled "Effect of Direct Access" to address the scenario where a customer under an LLCA opts into a direct access schedule. Such customers would no longer be subject to the generation minimum demand charges once they are

---

[204] PGE/400, Ferchland-Barrow-Jose/46-47.
[205] *Id.*

on direct access because PGE will no longer procure generation for these customers. Instead, the customer will pay for the applicable direct access transition adjustment, which reflects transition charges. These charges apply because PGE has planned and procured resources in advance to serve this load, and the customer has elected to leave PGE's cost-of-service for direct access.

Additionally, as shown above, existing customers under an LLCA opting into direct access will be required to pay a transmission demand charge for the difference between actual usage and the minimum transmission demand set forth in the LLCA.

This charge is necessary because PGE cannot apply the minimum transmission demand charge to an electric service supplier. An electric service supplier pays transmission charges to PGE pursuant to PGE's Open Access Transmission Tariff based on the electric service supplier's forecast and actual usage. Because PGE will be constructing transmission facilities based on forecasts of customer commitments in an LLCA, PGE must maintain a commitment that a minimum transmission charge will be recovered from the customer to guarantee the revenue requirement recovery from the customer(s) who contributed to the need for new transmission facilities. This proposal is consistent with cost-causation principles. Without such a minimum charge in place, a customer could potentially use direct access as a way to avoid paying a minimum transmission charge for facilities that PGE has built in response to increased system demand from the customer.[206]

---

[206] PGE/400, Ferchland-Barrow-Jose/47.

## 36. What other contract terms may be required to comply with HB 3546? (See CRITFC Recommendations, CRITFC/301, DeCoteau/9-19).

***PGE's Proposed Contract Terms Are Strong and Provide Sufficient Safeguards to Protect All Customers***

There are no other contract terms required to comply with the POWER Act than those that have been outlined elsewhere in this brief.[207]

PGE's proposed contract terms, as previously discussed, were analyzed by London Economics International, which determined that "PGE's Schedule 96/Rule I is more protective of non-data-data center customers and keeps more cost responsibility on potential data center customers based on their contracted demand and the proposed minimum demand charges for distribution, transmission and generation. Efficiency of the rate design for PGE's proposed Schedule 96/Rule I is also promoted by the exceedance penalty – other than AEP Ohio, the other utilities did not provide transparent exceedance penalties to protect other customers from free riding by data center customers; and the penalty encourages the data center customer to give an accurate estimate of contracted demand. PGE's charges are more transparent and, because of that, more predictable than jurisdictions which negotiate such terms in the ESA [electric supply agreement]. This may be perceived by potential large load customers as lowering the risk of building and operating a data center in PGE's territory."[208]

PGE's proposed contract terms are sufficiently robust to protect existing customers and the utility from the risks inherent in adding new data centers and large loads to the system without including terms that are too extreme and prohibitive for prospective customers.

---

[207] PGE/400, Ferchland-Barrow-Jose/50.
[208] PGE/300, Fagan-Frayer/27.

### 37. Should any contract terms be revisited in PGE's next general rate case?

***The Contract Terms Are Durable***

The contract terms proposed by PGE should be maintained going forward to promote transparency and consistency in the market and permit market reliance that these thoroughly evaluated contract terms will not change based on future rate cases. As the contract terms resulting from this docket will be the product of multiple months of analysis, review, parties' feedback and a Commission order, it is reasonable for PGE and the market to be able to plan long-term for the contractual requirements to stay the same.

### 38. Should customers who are not required to enter into a Minimum Load Agreement or LLCA be eligible to opt-in to one of these service contracts at their discretion? (See PGE/407, Ferchland-Barrow-Jose/25 for the proposed redline change clarifying the option for a customer to elect to enter into a customer contract)

***Customers Should Be Able to Opt-In to a Contract at PGE's Discretion***

The Commission should approve the ability for a customer who is not eligible for an LLCA or MLA to be able to opt-in to an MLA or LLCA subject to PGE's approval and discretion. In some instances, a prospective customer seeks to opt-in to an MLA or LLCA when they would not otherwise need to sign one. PGE believes that prospective customers should be able to opt-in if, upon review of the request, PGE agrees with entering into an MLA or LLCA with the customer. This should be allowed by the Commission because, as discussed, MLAs and LLCAs bring a suite of protections to other customers and, by allowing the opt-in, these customers will be selecting into more – not less- requirements.[209]

[209] PGE/407.

**39. Should the Commission require PGE to hold unused capacity for customers without a system capacity allocation contract (LLCA or active MLA)? (See PGE/407, Ferchland-Barrow-Jose/7) for the proposed redline change clarifying system planning for capacity not under a contract with system capacity allocated.)**

***Unused Capacity Should Not be Held By PGE***

Holding unused capacity is not standard for PGE and it does not occur today outside of the initial five-year period of a minimum load agreement. PGE does not recommend a requirement to hold unused capacity for any customer class or customer outside of contracted capacity allocation because it does not benefit the system or PGE's customers to hold capacity back from the system if it is available for use. To the extent that data center or large load customers need capacity, it should be allocated through contractual terms.

**40. Should substation upgrade costs for general load growth (1MW to 3.99MW) customers be the responsibility of applicant? (See PGE/407, Ferchland-Barrow-Jose/47 for testimony on substation costs for general load growth.)**

***Substation Upgrade Costs for General Load Growth Under 3.99 MW Should be Paid by PGE, Not the Customer***

The Commission should accept PGE's redline changes proposed in Rule I to clarify substation upgrade costs requirements for general load growth (1MW to 3.99MW) should not be allocated to customer/applicant.[210]

PGE has customers of varied sizes, including customers that may require substation upgrades for general load growth above 1 MW and below 3.99 MW. For these smaller customers, PGE believes it would be appropriate for PGE, not the customer, to pay for upgrade

[210] PGE/400, Ferchland-Barrow-Jose /45-46.

costs to the substation. Applicants and customers will still be responsible for study fees associated with the substation upgrade. PGE believes that this change reflects the general growth aspect of these specific substation upgrades.

**41. How should costs associated with transmission facility upgrades deemed to be nonpermanent be allocated?**

***The Costs for Nonpermanent Transmission Facility Upgrades Should Be Allocated 100% to the Benefiting Customer***

PGE recommends that the Commission approve its request to allocate 100% of the costs for any nonpermanent transmission facility upgrades to the customer that is benefiting from that nonpermanent transmission facility upgrade.[211] This cost allocation is appropriate because, since the asset or upgrade itself is nonpermanent, it will be replaced by a permanent asset or upgrade.

**42. Should the concept of site aggregation be changed to account for commonly owned facilities within PGE service territory? (Staff/500, Stevens/48-49).**

***PGE's Site Aggregation Definition Should Remain Unchanged***

Parties have indicated their agreement with PGE's position that site aggregation as defined within its current tariff language, which the Commission approved, should be maintained.[212] Specifically, PGE's position is that the Commission should continue their support for the current tariff language for site aggregation for customers qualifying for an MLA or LLCA (Category 2 or 3), which is that buildings with like ownership that are within 2,500 feet or located greater than 2,500 feet away but are electrically connected will be considered as one site

[211] PGE/400, Ferchland-Barrow-Jose/46; *see also* PGE/407 at 28.
[212] Parties anticipate filing a stipulation to this effect on or after February 4, 2026. This section is included in the Opening Brief for completeness as it appeared in the contested issues list and the position statement, but we expect the issues to be addressed only in connection with the stipulation.

for Categories 2 and 3. The Commission should reject the idea to expand site aggregation to all like-owned facilities within the PGE service territory.[213]

**43. Does PGE have any additional clarifications to the language of Rule I that it proposed in this docket? (See PGE/400, Ferchland-Barrow-Jose/79 for the administrative addition of allocation methodology in the definition of Cost of Work.)**

***The 100% Allocation of the Cost of Exclusive Use Facilities to the Applicant Should be Included in Rule I***

The Commission should approve the new Rule I clarifying language that the cost of Exclusive Use facilities for an applicant will be allocated 100% to the applicant and the applicant will be assigned proportional costs of any new, additional, or upgraded distribution facilities to serve the applicant that are not exclusive use facilities.[214] This language documents the standard practice for the cost allocation of Exclusive Use facilities.

## F. Special Contracts

PGE's proposal supports including special contracts for data center customers. These special contracts would be subject to Commission oversight and approval and are an important avenue to provide data center customers with access to resources without increasing exposure to existing customers.

[213] PGE/200, Ferchland-Barrow/45.
[214] PGE/407 at 2.

## 44. Should the Commission approve the use of special contracts for Schedule 96 customers?

***Data Centers Should Be Able to Use Commission-Approved Special Contracts***

PGE's proposal offers optionality for large load data center customers who can choose between standard cost-of-service generation pricing under Schedule 96,[215] special contracts for generation resources, or a combination of both. PGE respectfully requests that the Commission approve the use of special contracts for Schedule 96 customers for the following reasons: 1) special contracts are expressly authorized by the POWER Act which approves of the use of special contracts to support new large loads with dedicated, customer-funded resources; 2) PGE has proposed a clear, comprehensive, and standardized regulatory framework to ensure that any special contract for dedicated resources for Schedule 96 customers receives appropriate Commission oversight consistent with the POWER Act; 3) the use of special contracts directly supports compliance with HB 2021 by enabling the procurement of clean, reliable resources tailored to specific large customer needs without compromising affordability for existing cost-of-service customers,[216] and; 4) special contracts preserve system reliability and planning integrity while ensuring that all costs and risks associated with serving large loads are fully and transparently borne by the participating customer.[217] Special contracts would serve as a robustly

---

[215] Under the cost-of-service option (Schedule 96), the customers' forecasted load would be incorporated into IRP subsequent procurement in RFPs and then included in PGE's AUT and GRC filings. The costs of growth-driven resource procurement are then allocated to the rate class via the PGM and collected through a generation demand charge and NVPC.

[216] PGE/400, Ferchland-Barrow-Jose/50, 53, 56, 57.

[217] PGE/400, Ferchland-Barrow-Jose/50, 53, 56, 57.

regulated route for data center customers to choose in addition to the existing RFP process, but they do not take the place of the RFP process.[218]

Any special contract must be approved by the Commission individually as discussed further in Section 48. PGE's proposed approach maintains regulatory rigor while providing customers with timely, structured contracting pathways that respect system reliability, transparency, and consumer protection.[219] Recent experience shows that shortlisted projects have withdrawn from RFPs after receiving offers from unregulated entities.[220] Allowing special-contract participation may help retain high-value renewable projects within Oregon's regulated framework, maintaining Commission oversight.[221]

PGE requests the Commission acknowledge the use of special contracts for generation, which enables timely development of clean, reliable resources that serve new large load data centers without shifting costs or risks to existing ratepayers.[222] These contracts allow PGE to procure generation in parallel with our core portfolio, helping maintain affordability and progress toward HB 2021 goals while ensuring data centers contribute to resource adequacy and decarbonization.[223] These contracts require explicit considerations for firmness, deliverability, integration costs, and operational performance.[224] By doing so, the special-contract pathway ensures that the customer driving the new load funds the full cost of resource adequacy contributions and operational risk, while protecting both system reliability and cost-of-service customers from cost shifts. Special contracts position PGE and Oregon as a strategic partner for

---

[218] PGE/400, Ferchland-Barrow-Jose/54.
[219] PGE/400, Ferchland-Barrow-Jose/54.
[220] PGE/200, Ferchland-Barrow/33-34
[221] PGE/200, Ferchland-Barrow/33-34.
[222] PGE/400, Ferchland-Barrow-Jose/51.
[223] PGE/400, Ferchland-Barrow-Jose/57.
[224] PGE/400, Ferchland-Barrow-Jose/51, 56.

responsible load growth that advances Oregon's clean energy and economic development goals.[225]

Under the Special Contract Option, customers contract directly with PGE for dedicated resources, either partial or full, to satisfying some or all of the customers' energy and resource adequacy obligations, bearing the full cost, including energy, capacity, integration, and operational risk, while PGE retains planning visibility and reliability responsibility.[226] This model recognizes the importance of allowing large customers to procure or enable new resources, without imposing costs on other cost-of-service customers, and that allowing this can accelerate Oregon's transition to a clean, reliable grid while protecting existing customers.[227]

Protecting existing customers from unwarranted cost shifting is central to PGE's proposal and directly aligned with the intent of the POWER Act. Reliability is the core of PGE's operational mission and ensuring that reliability is upheld without shifting costs or risks to existing customers is paramount. Although PGE remains the POLR for all customers pursuant to Division 38 rules, the special contract structure is expressly designed to ensure that POLR obligations do not result in financial exposure to cost-of-service customers.[228] Under the special contract framework, all costs, risks, and liabilities associated with procuring, integrating, and operating the dedicated resource are contractually assigned to the special contract customer.[229]

To reinforce this protection, Schedule 96 customers taking service under a special contract must provide or fund resources that satisfy PGE's planning standards for firmness, deliverability, and capacity accreditation, and they must cover any supplemental capacity needed

[225] PGE/200, Ferchland-Barrow/35.
[226] PGE/400, Ferchland-Barrow-Jose/52.
[227] PGE/200, Ferchland-Barrow/32-33.
[228] PGE/400, Ferchland-Barrow-Jose/52-53.
[229] *Id.*

to uphold system reliability. This ensures that the special contract customer, not existing cost-of-service customers, bears the full cost of maintaining resource adequacy. By aligning obligations with PGE's system planning and operational requirements, the framework preserves PGE's POLR role in form while preventing it from becoming a financial burden on nonparticipating customers.[230]

PGE's approach to procuring resources through special contracts would be grounded in the following principles. First, PGE would seek to preserve the core portfolio. PGE's regulated portfolio must first and foremost meet the needs of cost-of-service customers under the IRP and HB 2021 targets. Resources procured to serve large load data centers through special contracts should not alter the IRP-identified least-cost, least-risk portfolio that serves existing cost-of-service customers. Second, PGE would seek to enable structural parity. Large load data centers should bear their fair share of cost and carbon compliance obligations while benefiting from PGE's procurement expertise and scale, maintaining parity with electric service suppliers and other non-regulated providers. Third, PGE would seek to accelerate with discipline. Accelerated procurement should be possible outside the RFP cadence only when it demonstrably advances system benefits (e.g., resource adequacy, transmission utilization, decarbonization timing, or regional diversification).

As discussed, PGE intends to file each special contract for Commission approval under Section 5 of the POWER Act, accompanied by documentation of the resource's cost structure, performance obligations, and risk allocation. This review process provides regulatory transparency and maintains Commission oversight not available in other programs.[231] PGE intends to include in each filing the following: 1) analysis of costs, benefits, and risks in

[230] PGE/400, Ferchland-Barrow-Jose/51.
[231] PGE/200, Ferchland-Barrow/34.

comparison to cost-of-service procurement activities (e.g., RFP); 2) verification that the resource contributes to state reliability and decarbonization goals; 3) analysis of the resource(s) expected contribution to satisfy Resource Adequacy obligations; and 4) demonstration that the special contract meets the requirements of Section 5 of the POWER Act.

Under PGE's proposal, resources eligible for special contracts include, but are not limited to: projects that participated in but were not selected and executed for PGE's cost-of-service portfolio in PGE's RFP process, projects brought forward by PGE and the customer seeking Commission pre-approval allowing for a case-by-case waiver from competitive bidding when the project meets PGE's technical, deliverability, and environmental standards; or long-lead resources with deliverability outside the current IRP Action Plan and RFP timelines (e.g., geothermal, nuclear).

PGE does not propose to bypass its competitive RFP process. Rather, the special contract framework is intended to complement existing procurement tools while preserving flexibility to address customer-specific load timing and system needs.[232] Where a competitive RFP identifies a resource that is not ultimately selected and executed for PGE's cost-of-service portfolio, PGE may evaluate whether that resource is appropriate for a large-load special contract.

It is critical that PGE retain the ability to rely on both RFPs and bilateral procurement. The special contract framework is not intended to require an RFP as a condition precedent to serving large load customers, and imposing such a requirement would unnecessarily constrain PGE's ability to align procurement with system conditions and customer load ramps. All resources procured under a special contract, whether identified through an RFP or bilateral

[232] PGE/400, Ferchland-Barrow-Jose/3.

negotiations, remain subject to Commission oversight to ensure prudence, fairness and that there is no cost-shifting to core customers while preserving reliability and planning integrity.

This special contract approach allows PGE to align resource procurement with customer load-ramp timing and accommodate unique resource attributes, such as 24/7 clean energy matching, customer sited generation, or long-lead resources necessary to satisfy resource adequacy requirements.[233] Additionally, unlike direct access, special contracts preserve PGE's visibility into load and resource development and ensure alignment with system planning. Special contracts, as approved by the Commission, provide a regulated avenue for retaining such projects while ensuring that all associated costs remain with the contracting customer. By embedding these standards directly into the contract terms, PGE ensures that resource adequacy is preserved and that new load contributions are aligned with system planning needs. [234] Accordingly, the bilateral pathway is essential both to maintaining system reliability and to prevent loss of high-value renewable projects to unregulated procurement.[235]

**45. Should PGE be limited to the types of resources that can be procured via a special contract as proposed by the Coalition (Coalition/400, Souder/40)?**

***There Should Not Be Additional Restrictions on the Use of Special Contracts***

The Commission should reject additional, unnecessary restrictions on the use of special contracts. As the Commission will have the opportunity to approve all special contracts either on an individual basis or in a future proceeding in which the Commission establishes the framework

[233] PGE/400, Ferchland-Barrow-Jose/54.
[234] PGE/400, Ferchland-Barrow-Jose/51-52.
[235] PGE/400, Ferchland-Barrow-Jose/54-55.

for such special contracts, it is premature to consider limitations on the types of resources that could be used in a special contract.

### 46. How should the Commission review Special Contracts under HB 3546 Section 2(3) review criteria?

***Special Contracts Will be Reviewed and Approved by the Commission***

Special contracts will be reviewed and approved by the Commission. Pursuant to the POWER Act and the process we are proposing, any special contract must be approved individually by the Commission. In the future, it may be appropriate for the Commission to approve a special contract framework for certain special contracts. At this time, and as is reflected in our draft Schedule 96, PGE proposes that special contracts be approved by the Commission.[183] The proposed Commission oversight and approval process is specifically designed to ensure that these projects do not circumvent least-cost, least-risk protections or shift costs in ways that disadvantage the broader cost-of-service customer base.

PGE commits to filing documentation that details the resource's cost structure, performance obligations, and risk allocation as previously discussed. This allows the Commission to confirm that costs are fairly allocated and that the resource acquisition does not compromise the least-cost, least-risk portfolio intended for existing cost-of-service customers.[236]

## G. CIAC

CIAC is a long-standing utility concept that allows customers to make a contribution towards the construction of equipment that serves that customer.[237] As CUB states, "[i]f these companies want to help pay for the infrastructure necessary to serve them, it should not only be

[236] PGE/400, Ferchland-Barrow-Jose/53.
[237] CUB/100, Jenks/43.

allowed, it should be encouraged."[238] PGE's proposed revision to Rule I is that prospective customers can elect up to 50% of CIAC for distribution,[239] but PGE is open to permitting a customer election of up to 100% CIAC for the cost of distribution assets for distribution facilities providing no material shared system benefit (for example, when infrastructure serves a single customer or a dedicated service point).[240] The proposed revision to Rule I will state (if 50%), as appears in italics:

*Customer may elect to contribute up to fifty percent (50%) of the Cost of Work via a Contribution in Aid of Construction (CIAC) payment. Should a Customer elect to provide a CIAC, upon energization, they will be issued a CIAC Distribution Credit divided by 12 until such time that the original CIAC contribution has been returned to the Customer. This may apply to Customers with an MLA or LLCA.*[241]

PGE understands that several parties support up to 100% CIAC for distribution. It is appropriate to consider CIAC for distribution facilities because they are clearly customer-specific, which strikes the appropriate balance in allocating costs. It ensures that customers pay for infrastructure built exclusively for their benefit, while preserving the utility's obligation to plan, own, and recover the cost of generation and transmission assets that serve the public at large[242]. In the future, PGE is also willing to explore shifting from discretionary CIAC (permitting the prospective customer to choose) to an in-part or whole obligatory CIAC for certain future distribution projects if PGE is deemed capital constrained. The metric for when

---

[238] CUB/100, Jenks/43 at 18-20.
[239] PGE/407.
[240] PGE/400, Ferchland-Barrow-Jose/48; parties anticipate filing a stipulation to this effect on or after February 4, 2026. This section is included in the Opening Brief for completeness as it appeared in the contested issues list and the position statement, but we expect the issues to be addressed only in connection with the stipulation.
[241] PGE/407.
[242] PGE/400, Ferchland-Barrow-Jose/49.

PGE is deemed capital constrained would have to be defined in Rule I. As discussed next, the reasons that CIAC make sense for distribution are the same reasons it does not make sense for fixed generation or transmission.

**47. Should CIAC be allowed for new permanent transmission assets and for fixed generation assets and, if so, to what percentage?**

***The Commission Should Reject CIAC for Fixed Generation Assets or Permanent Transmission Assets***

PGE does not support CIAC on generation and transmission investments because these assets provide broad, systemwide reliability and benefits that extend beyond any single customer and therefore are most appropriately funded through regulated cost recovery. CIAC for fixed generation or new permanent transmission assets would distort cost allocation, undermine coordinated planning, and erode key financial and tax benefits, ultimately increasing long-term costs and reducing PGE's ability to invest in infrastructure critical to reliability, decarbonization, and equitable customer service.[243] Further, the Commission should not allow CIAC for fixed generation assets or new permanent transmission assets because permitting CIAC would require the Commission and parties to determine on a project-by-project basis if an investment is primarily driven by a particular customer; this analysis is inherently speculative in a networked system and inconsistent with long-standing Commission precedent favoring system-based allocation for shared infrastructure. Allowing CIAC for fixed generation assets or new permanent transmission assets would, over time, discourage timely investment in critical backbone facilities and increase disputes over cost responsibility.[244]

---

[243] PGE/200, Ferchland-Barrow/31.
[244] PGE/400, Ferchland-Barrow-Jose/49.

## H. HB 2021 and HB 3546

PGE's proposal is put forward to the Commission with HB 2021 and the POWER Act's frameworks in mind. As explained in further detail below, PGE's request for Commission approval in this docket will enable our full compliance with the Power Act.

### 48. How should HB 2021 be considered by the Commission in this docket?

***PGE's Proposal Meets the Requirements of The POWER Act That Relate to HB 2021 Targets***

HB 2021 carbon emission targets are relevant to this docket only insofar as the Power Act mentions them as factors for the Commission's consideration in reviewing and approving the formation of a large load data center customer class. The challenges in meeting the HB 2021 carbon emission targets are topics for PGE's IRP and CEP. As we've detailed and other parties in this docket acknowledge, PGE faces a variety of headwinds to meeting those targets that are independent of data center growth, including:

- Lengthy permitting and siting timelines for generation and transmission;
- Transmission congestion and interconnection delays;
- Supply chain disruptions and escalating construction costs; and,
- Evolving federal tax incentives and policy uncertainty.

These considerations as well as factors related to large load growth's impact on PGE's progress towards HB 2021 targets are relevant and important for PGE's next IRP and CEP but they are not relevant in this docket except to the degree identified in the POWER Act.

Section 2(3) of the POWER Act sets forth the factors the Commission should consider when reviewing rates applicable to a large load data center customer class. These factors include whether the *proposed rates* either impede the utility's ability to meet HB 2021 carbon emission targets or reduce carbon emissions consistent with state policy (section 2(3)(c)) or allow for the procurement of or contracts for generation resources that support the utility's ability to meet the HB 2021 carbon emission targets or reduce carbon emissions consistent with state policy (section 2(3)(d)). These are the only factors identified in the POWER Act for the Commission to consider in this docket that are related to HB 2021.

Nothing in Schedule 96 rates impedes our ability to meet these targets or our ability to acquire generating resources to support our ability to achieve these targets. To the contrary, the proposal enables PGE to procure generation resources through special contracts that support decarbonization. By enabling PGE to serve large load data centers and requiring them to pay their full cost of service, Schedule 96 ensures that these customers contribute to the infrastructure investments required to meet HB 2021 goals. Furthermore, any special contracts signed under this schedule must be submitted for Commission review, ensuring ongoing alignment with state emissions targets.[245]

PGE's proposal supports its efforts to reach the HB 2021 carbon emission targets and reduce carbon emissions consistent with State policy. It furthers HB 2021 overarching goals by allowing PGE to serve data centers located in our service territory and thereby controlling how scarce renewable resources in the region are allocated between customer classes. Furthermore, if PGE serves these loads, they will be subject to state carbon emission requirements applicable to PGE, which are more stringent than those that apply to loads served by electric service supplier or consumer-owned utilities. In this way, enabling PGE to serve large data center loads promotes

---

[245] PGE/400, Ferchland-Barrow-Jose/61.

the State's carbon emission goals by increasing the amount of load in Oregon subject to these requirements.[246]

**49. Do the proposed Schedule 96 and the marginal cost allocations proposed by PGE comply with HB 3546?**

***PGE's Marginal Cost Allocation Proposals and Schedule 96 Comply with HB 3546***

PGE's proposal for updating marginal cost allocation and Schedule 96 complies fully with the POWER Act.[247] Specifically, the POWER Act provides that tariff schedules must do two primary things. First, it ***must allocate the costs*** of serving the data center class of customers 20 MW or over ***to the class in a manner that is equal to or proportional to the costs of serving the class*** or directly assign the cost of serving a member of the data center class to the class member.[248] Second, it must mitigate the risk of other customer classes paying unwarranted costs or the shifting of costs to other customer classes.[249] While deciding whether the proposed tariff should be approved, the Commission is directed by the Legislature to consider whether the rates result in, or have the potential to result in, increased costs or unwarranted risk to other retail electricity customers; provided for equitable contributions to grid efficiency, reliability, and resiliency benefits; impeded the utility's ability to meet state clean energy targets or reduced the emissions of greenhouse gases consistent with state policy; allowed for the procurement of or

[246] PGE/400, Ferchland-Barrow-Jose/60.
[247] PGE/400, Ferchland-Barrow-Jose/62.
[248] ORS § 757.292 (2)(a)(A)-(B). (Emphasis added).
[249] ORS § 757.292 (2)(c)(A-B).

contracts for generation resources that support the same; and met any other conditions the Commission may require in the public interest.[250]

PGE's proposal, as the evidence shows, allocates the cost of serving the data center customers in a manner that is equal or proportional to the costs of serving the data center class and also mitigates the risk of other customer classes paying unwarranted costs or shifting the costs to other customer classes. Our proposal, if approved as presented, does not result in increased costs or unwarranted risk to other retail customers. Rather, it is anticipated to result in decreased rates for certain customers through the updated marginal cost allocation. The proposal also enables equitable contributions to grid efficiency, reliability, and resiliency benefits from the data center customer class and other large load customers and PGE's compliance with HB 2021. Further, as established, the proposal does not impede, in any way, PGE's ability to comply with HB 2021.

**50. Does HB 3546 or HB 2021 require any additional measures or transparency not present in PGE's proposal? (CRITFC/400, DeCoteau 8-12).**

***PGE's Proposal Does Not Require Modification***

For the reasons discussed above, the Commission should find that the POWER Act and HB 2021 do not require any additional measures or transparency than those already proposed by PGE.[251] In addition, it is not clear in the record what additional measures and transparency requirements are sought.

[250] ORS § 757.292 (3)(a-e).
[251] PGE/400, Ferchland-Barrow-Jose/50.

**51. Should the Commission require any other conditions to this Schedule 96 proposal under HB 3546 Section 2(3)(e) to meet the public interest?**

***Additional Requirements Are Not Needed to Meet the Public Interest***

PGE's proposal encompasses thoughtful, sufficient protections that shield existing customers from additional risk presented by data centers and large load customers joining the system without depriving customers of the benefits that come with system growth. PGE's proposed Schedule 96 and other adjustments in this docket builds a growth-pays-for growth paired with a peak-usage-pays-for-peak-usage pricing structure that is workable long term and fully compliant with HB 2021 and the POWER Act. As proposed, the cumulative result is no cross-subsidization of Schedule 96 customers,[252] it satisfies the public interest, and additional requirements are not needed.

## I. Queues for Large Load Customers

PGE's proposal is comprehensive and includes appropriate requirements for prospective customers and it would not be appropriate to add an additional queuing requirement that is predicated on particular conditions, as discussed further, below.

**52. Should PGE be required to establish a queue for Schedule 96 customers or large load customers generally based on the considerations suggested by Staff (Staff /400, Bolton/2)**

***Large Load Customers Should Be Able to Connect as Other Customers Can Connect to the System***

PGE has identified reasonable requirements for data centers and large loads to connect to the system and the Commission should not enact an additional, prohibitive requirement that is

[252] PGE/400, Ferchland-Barrow-Jose/4-5, 50.

being characterized as a queue but that is, in effect, a denial of service that treats specific customer classes disparately. PGE believes that it is inequitable and unreasonable to require a queue that is structured to block customers from being served by PGE and from entering service until restrictive and undefined conditions are met. The suggestion that data center or large load customers are barred from being served until narrow criteria are met (special contract for generation, direct access service, or undefined flexible load) flies in the face of PGE's obligation to serve customers without undue discrimination. Allowing direct access to be prioritized for service also, as previously discussed, undercuts Oregon's clean energy and lower carbon emissions goals. The creation of a queueing system with such narrow and demanding requirements to exit the queue, would, by definition, cause Schedule 96 or large load customers to be treated differently from other retail customers.

HB 2021 established carbon emission targets that apply to the generation and power purchases serving all of PGE's load (residential, commercial, industrial) alike and does not distinguish between customer classes, nor does it authorize the Commission to condition service to a particular class on the achievement of statewide emission targets. The creation of a queue and the requirement that only a subset of all customers use the queue would cause delay and denial of service for specific customers in a manner that is neither contemplated by nor consistent with law.[253]

Indeed, a queue with such a requirement would undermine the overarching goals of HB 2021 because large load customers would then seek service instead from an electric service supplier (without a queue and with far less-stringent carbon intensity requirements) or a customer-owned utility (without a queue and with no carbon emission requirements and outside

[253] PGE/400, Ferchland-Barrow-Jose/59-60.

the purview of the POWER Act and the associated cost shift protections).[254] Finally, if the Commission wishes to pursue this option, further work in a subsequent proceeding is required to define the proposed requirements for exiting the queue and other implementation issues that have not been sufficiently supported in the record in this proceeding.

In contrast with Staff's queue proposal, PGE's proposal is to serve load based on available system capacity based primarily on transmission constraints and customer provided-flexibility, which is administered through the study process outlined in Rule I.[255] Rule I uses the term "queue" to refer to a "capacity queue," which relates to the application and study process[256] and, while customers do need to successfully complete the application and study process, the requirements in PGE's queue process concern PGE's ability to interconnect and serve large customers based on their needs and proposed timeline. Unlike Staff's queue, these reasonable requirements exist for all customer classes and every customer has a similar opportunity to connect subject to the results of the cluster study process outlined in Rule I. Thus, PGE's capacity queue is not discriminatory, nor does it have the consequential impact of driving customers to providers with lower or no HB 2021 requirements.

**53. Should PGE establish a fast-track queue for flexible loads?**

***A Fast-Track Queue is Not Needed***

PGE does not support the establishment of fast-track interconnection queues for asset-backed flexible loads as proposed by Verrus.[257] PGE's established practice is to serve load based on available system capacity and this practice already accounts for customer-provided flexibility

[254] PGE/400, Ferchland-Barrow-Jose/60.
[255] PGE/400, Ferchland-Barrow-Jose/61.
[256] *See* PGE/407 (Generally, customers applying in Category 1 and in Category 2A or 2B with less than 4 MW will be first-come, first served in study process where possible; Category 2A, 2B with more than 4 MW and all Category 3 customers will be placed in a cluster study).
[257] Verrus/200, Bladen/8.

as a means to accelerate the interconnection of the customer providing flexibility based on the specific system benefit that the customer's flexibility brings.[258]

PGE does not support establishing a formal fast-track interconnection queue for flexible loads because the existing approach to large load customers is structured so that customers with large system capacity needs bringing customer-provided flexibility receive approval for service rapidly. PGE's cluster study process already includes the determination of a firm (non-flexible) ramp and timing, as well as the accelerated and increased ramp possible considering the individual customer's proposed flexibility. This process effectively allows for the "fast track" connection of customers providing flexibility based on the specific benefit accrued by the customer's flexibility.[259] Further, in addition to a separate "fast-track" process being unnecessary, the creation of a separate "fast-track" process would likely extend the study process for all customers in comparison with the current approach. This is because the study process would have to be bifurcated, creating delay and administrative separation between customers based on whether they bring flexibility.

## J. Reporting

PGE has consistently fulfilled its obligation to provide information to the Commission necessary for the Commission's regulation of the utility. In addition to long-term planning processes, such as the IRP/CEP and rate cases, there are investigative dockets such as this one that provide substantial record evidence and information about PGE's assets, plans, and service. The flow of information to the Commission and the public is frequent, appropriate, and sufficiently robust. Requiring additional reporting is not warranted.

---

[258] PGE/400, Ferchland-Barrow-Jose/30, 61.
[259] PGE/407 at 16; PGE/200, Ferchland-Barrow/42.

**54. Should the Commission order in this docket any additional reporting requirements related to HB 3546 Section 7?**

***The Commission Should Reject Additional Reporting Requirements***

In this matter, certain parties have suggested that additional reporting should be directed by the Commission. The reporting requirement set forth in Section 7 of the POWER Act is a sufficient reporting requirement. This section requires the Commission to submit a report biannually that will "…review trends in load requirements and other implications from retail electricity consumers that are large energy use facilities, as defined in Section 2 of this 2025 Act, and other retail electricity consumers that use large amounts of electricity..." In addition to this established reporting requirement, this Commission facilitates robust public processes that include PGE reporting on resource use, capacity, capital, and other aspects related to all customer classes. For example, the IRP/CEP process, which includes thorough review of the comprehensive roadmap to meet customer energy needs.

## K. Additional Topics

In addition to the aspects of the proposal discussed previously, there are two more items raised within this docket, which are discussed next.

**55. Should the Commission require PGE seek tribal consultation as facet of Schedule 96 or otherwise to comply with HB 3546 and/or HB 2021, as CRITFC has proposed? (CRITFC/400, DeCoteau 8-12).**

***Tribal Consultation Should Occur As It Does Today, Without an Order in This Docket***

PGE supports broader tribal engagement on a variety of issues, to include data centers, but does not believe that requiring PGE's consultation with tribal entities is appropriate for the

Commission to order as a part of Schedule 96 or otherwise. PGE's proposals are in compliance with the POWER Act and HB 2021.[260] While PGE greatly values tribal consultation, it also recognizes that tribal consultation under HB 2021 is an obligation of the State of Oregon in a government-to-government capacity, and not a requirement that can be directed at PGE within this docket, but PGE welcomes the opportunity to participate in the state's consultation.[261] As a reflection of PGE's belief that increased community stakeholder engagement is important, PGE is in the process of launching regional Community Advisory Councils to serve as a planning body to support PGE capital projects. There will be a dedicated tribal seat on each of the four councils. PGE welcomes continued engagement, collaboration and partnership with CRITFC and tribal governments and communities but does not believe that any direction or prescription of such consultation should be included in this docket.[262] If the Commission believes that additional consultation is required related to data centers and large loads, PGE believes that the State of Oregon is the best situated to fill this role, especially as it is so designated by the Legislature.

**56. Should the Commission address any other topics than those identified above that are appropriately within the scope of this docket?**

***PGE's Study Expiration Periods Should Be Included in Rule I***

It is important that customers understand that study results for load feasibility, system impact, and facilities study results will not be permanent. PGE proposes clarification in Rule I that documents PGE's current practice related to study expiration periods. Parties have not objected to this proposal, which PGE considers administrative in nature. Previously, Rule I did

[260] PGE/400, Ferchland-Barrow-Jose/4-5, 50.
[261] ORS § 469.A.405, "[i]t is the policy of the State of Oregon that, under existing federal and state law, ***the state*** engages in meaningful consultation with federally recognized Indian tribes..." (Emphasis added).
[262] PGE recognizes that tribal consultation is required in certain instances, such as those with a federal nexus related to specific projects, but it is not addressing this consultation here.

not include reference to study expiration periods or for how long the study results would be valid. The purpose of the inclusion of the language is to clarify within Rule I the established practice, which is expiration after 60 days. Specifically, the language proposed would read as in *italics*:

> *All study results will expire 60 days from issuance. Applicant may request an extension of the validity of the study results for no longer than 365 days from issuance. Company may grant an extension of the validity of the study results so long as no other customer has applied for capacity on infrastructure the Company deems necessary to serve Applicant's load request. In the case where another customer applies for capacity on infrastructure the Company deems necessary to serve Applicant's load request, the Company will notify an Applicant with an extension that such application has been received and will issue Applicant a revised timeline to authorize the Company to proceed with design of the Line Extension or execute a subsequent study agreement, whichever is offered by the Company. Applicant will forfeit their place in the capacity queue as described in Section 4 of this rule if the validity of their study results expires without Applicant providing formal authorization to the Company to proceed with design of the Line Extension or Applicant fails to execute a study agreement offered by the Company before the expiration of the study results.*[263]

This is a sensible, administrative revision that clarifies the study expiration period and will increase transparency for the public about an existing, standard practice if it is included in Rule I.[264]

## VI. Conclusion

Each piece of PGE's proposal in this case is designed to strengthen cost accountability, focus on affordability, support Oregon's clean energy goals, and align with the purpose and requirements of the POWER Act. Collectively, the changes ensure the fair and forward-looking recovery of new large connection costs and reflect the Commission's statutory obligation to

[263] PGE/407 at 8-11.
[264] Parties anticipate filing a stipulation to this effect on or after February 4, 2026. This section is included in the Opening Brief for completeness as it appeared in the contested issues list and the position statement, but we expect the issues to be addressed only in connection with the stipulation.

ensure just and reasonable rates, prevent undue cost shifting, and maintain safe and reliable electric service for all customers. This docket presents the Commission a choice of which direction future system growth and development in Oregon will occur: through robust, regulatory review encompassing clean energy statutory framework or through requiring conditions that are so extreme that data centers and large load customers leave PGE for largely non-regulated or less-regulated providers with lessened or no clean energy requirements that nonetheless may undermine our ability to acquire the limited number of affordable, clean energy resources for PGE's customers.

The Commission should approve PGE's proposal and chart a way forward for Oregon that enables serving customers in an affordable, reliable, resilient, responsible, scalable, and equitable way.

DATED this 4th day of February, 2026.

**PORTLAND GENERAL ELECTRIC COMPANY**

David F. White
Senior Managing General Counsel
121 SW Salmon St, 1WTC1301
Portland, OR 97204
Phone: 503-464-7701
Email: David.white@pgn.com

## Appendix A

## Key Issues Reference

PGE's proposal includes multiple key issues. For reference, this crosswalk maps the key issues and interlocking subjects to PGE's position statement and the issues list. The table below indicates the key issue and where the correlated subjects appear in the brief, position statement, and issues list (the numbering matches in all three).

| Key Issue | Subject | Position | Issue Number / Brief Beginning Page Number |
|---|---|---|---|
| **Cost Allocation** | Marginal Cost Update | Marginal cost for generation, transmission, and distribution should be updated. | 8 / 26<br>9 / 31<br>11 / 33<br>21 / 56 |
| | Peak Growth Modifier (PGM) | PGM should be approved for an initial three-year period rolling to 10 years without weather normalization because weather is accounted for. | 13 / 35<br>14 (a-b; d-e) / 38, 43-44<br>23/58 |
| | Growth-Related Definition | Definition of growth-related (triggered by new or increasing load for transmission, or need for incremental capacity or energy to reliably serve increased demand for generation) should be adopted. | 14 (c) / 41 |
| | NVPC Update | NVPC should be updated with the energy growth modifier. | 16 / 45 |
| | Direct Assignment | Direct assignment of fixed generation and transmission | 17 / 47<br>18 / 53 |

| | | | |
|---|---|---|---|
| **Cost Allocation** | | should be rejected, including for Shute and Evergreen substations, and if direct assignment is adopted of fixed generation or transmission, it should be revisited immediately. | 19 / 55 |
| | Energy Efficiency (EE) Impact on Marginal Cost Study Allocation | EE does not directly factor in, but adjustment should be adopted to recognize residential investment to EE. | 10 / 32 |
| **Contract Terms and Customer Protections in Rule I and Associated Issues** | Minimum Contract Length for LLCA | Minimum contract term of 10 years initial, with 3 years renewal. | 24 / 59 |
| | Creditworthiness and Collateral Terms | Creditworthiness and collateral changes should be approved. | 25 / 61 |
| | Minimum Demand Charges | Minimum demand charges for transmission, generation, and distribution at 80% should be approved; if minimum distribution demand charge is rejected, flat-billed distribution demand charge should remain. | 26 / 63<br>27 / 66 |
| | System Capacity Deposit | System capacity deposit should continue to be approved. | 28 / 67 |
| | Exceedance Penalty | Exceedance penalty of 4-times transmission rate multiplied by the actual demand minus the threshold, without a buffer. | 29 / 68 |
| | Make Whole Provision | Make Whole Provision should be approved and refundable if capacity is reallocated to a new customer as applicable; funds would be applied as specified. | 30 / 70<br>32 / 73<br>33/ 74 |

| | | | |
|---|---|---|---|
| **Contract Terms and Customer Protections in Rule I and Associated Issues** | Exit Fees | Exit fees should be approved and refundable up to three years; funds would be applied as specified. | 31 / 71<br>32 / 73<br>33/ 74 |
| | Kilowatt Threshold for LLCA | 20,000 kW should be the threshold to enter LLCA. | 34 / 74 |
| | Opt-In for LLCA/MLA | Customers should be able to opt-in to LLCA or MLA with PGE's discretion. | 38 / 81 |
| | Direct Access Requirements and Costs for Non-Prior Cost-of-Service LLCA Customer | In addition to charges and adjustments in applicable direct access schedule, standard system capacity deposit, exit fee, and minimum distribution demand; modified minimum transmission demand, and no minimum generation demand. | 35 / 75 |
| | Direct Access Requirements and Costs for Prior Cost-of-Service LLCA Customer | In addition to charges and adjustments in applicable direct access schedule, standard system capacity deposit, exit fee, and minimum distribution demand; modified transmission demand; transition adjustment fee; no minimum generation demand. | 35 / 75 |
| | Additional contract terms and review | Additional contract terms are not needed to comply with the POWER Act and the contract terms should not be revisited during PGE's next general rate case. | 36 / 80<br>37 / 81 |
| | Unused System Capacity | PGE should not hold unused system capacity for customers without a contracted allocated system capacity. | 39 / 82 |

| | | | |
|---|---|---|---|
| **Contract Terms and Customer Protections in Rule I and Associated Issues** | Substation Upgrade Costs for General Load Growth below 4MW | PGE will pay for substation upgrades below 4MW because it is general load growth. | 40 / 82 |
| | Nonpermanent Transmission Facility Upgrades | Benefiting customer should pay 100% of nonpermanent transmission facility upgrade. | 41 / 83 |
| | Site aggregation | Current site aggregation definition should continue to be used. | 42 / 83 |
| | Additional Rule I Clarifications | Rule I should include the allocation of 100% cost for distribution Exclusive Use Facilities to customer and proportional costs for non-exclusive new, additional, or upgraded distribution facilities made to serve customer.<br><br>Rule I should include that all load feasibility, system impact, and facilities study results expire 60 days after issuance,<br>with additional potential extension time that may be granted by PGE. | 43 / 84<br><br>56 / 103 |
| | CIAC | CIAC of up to 100% should be allowed for distribution only. | 47 / 93 |
| | Special Contracts for Schedule 96 and large load customers | Special contracts should be allowed without limitation on the types of resources that can be procured and should be reviewed as informed by the POWER Act and approved by the Commission. | 44 / 85<br>45 / 90<br>46 / 91 |
| | Queue for interconnection | There should not<br>be additional requirements for interconnection, which would be a denial of service, or a | 52 / 98<br>53 / 100 |

| | | | |
|---|---|---|---|
| **Contract Terms and Customer Protections in Rule I and Associated Issues** | | fast-track queue for flexible loads because flexibility is already considered. | |
| | HB 2021 | Schedule 96 enables ability to procure generation resource s through special contracts to support decarbonization. | 48 / 94 |
| | Demand Charge for Schedules 89 and 90 | Demand charge should be approved for fixed generation instead of current volumetric charge. | 5 / 20 |
| **Process Issues** | Docket Scope | The docket applies to the impact on all customers from all large load customers, not just data centers. | 1 / 15 |
| | Implementation | Decisions should be implemented as soon as practicable upon docket's c onclusion through compliance filings. | 7 / 22 |
| | Data Center Class (Schedule 96) | Schedule 96 should be approved without a flexible load subclass. | 2 / 17<br>3 / 18 |
| **Other Issues** | Surcharge for Non-Cost-Effective Energy Efficiency | No surcharge should be added. | 4 / 19 |
| | Maximum Fee Under HB 3141 | The application of a maximum fee under HB 3141 should be rejected. | 6 / 21 |
| | Distribution Assets Placed into Base Rates | Distribution assets should be placed into base rates when connected to the system and determined to be prudent. | 12 / 34 |
| | But-For Analysis in the Next CEP/IRP | This should not be ordered. | 15 / 44 |
| | Double-Counting of Costs | The proposal does not result in any double-counting of costs. | 20 / 55 |
| | Regulatory Assistance Project (RAP) Proposal | PGE's proposal should be approved and the RAP | 22 / 57 |

| | | | |
|---|---|---|---|
| Other Issues | | proposal should not be evaluated at this time. | |
| | POWER Act, HB 3546 | Schedule 96 and PGE's proposal comply fully with POWER Act, no additional conditions are necessary to meet the public interest, and no additional reporting should be required. | 49 / 96<br>51 / 98<br>54 / 102 |
| | HB 3546 or HB 2021 Additional Measures or Transparency | No additional measures or transparency are required in addition to what is proposed by PGE. | 50 / 97 |
| | HB 3546 and/or HB 2021 Tribal Consultation | PGE welcomes and values tribal consultation, but it should not be ordered within this docket. | 55 / 102 |