ORDER NO. 26-154

ENTERED 05/07/2026

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2377

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I.	ORDER

DISPOSITION: SCHEDULE 96 ADOPTED WITH MODIFICATIONS; REVISIONS TO SCHEDULES 89 AND 90 ORDERED; REVISIONS TO RULES C AND I ORDERED; FIRST PARTIAL STIPULATION ADOPTED

I. INTRODUCTION

In this order, we address numerous issues related to the design of Portland General Electric Company's (PGE) tariff for large loads, including creation of a customer class for data centers, specifically. While we opened this investigation in response to concerns raised in prior rate case proceedings on large loads from multiple sources, the passage of House Bill (HB) 3546, the POWER Act, created an additional statutory foundation for our work. This decision marks the first implementation of that statute, where the Legislature directed the Commission to allocate or directly assign the costs of serving a data center to those customers specifically and mitigate the risk that other classes of customers are paying unwarranted costs.

While the Commission has long sought to avoid unwarranted cost shifting between customer classes, the scale of data centers and the rate at which they are requesting service from PGE create unique versions of otherwise well-understood risks and opportunities posed by large loads. Our decision below is intended to address these emerging risks and opportunities in a manner that protects other customer classes, emphasizes continued progress towards Legislative mandates such as HB 2021 and the small-scale renewable capacity requirement, and creates a predictable path forward for data centers that want to locate in PGE's service territory.

To that end, we implement in this order a suite of provisions designed to prevent cost shifting between customer classes, as the POWER Act requires, and to protect compliance with HB 2021, also required by the POWER Act. We include minimum transmission and generation demand provisions of 90 percent of contracted capacity, and a flat billed distribution charge covering 100 percent of the cost to expand the distribution system, as well as exceedance penalties, minimum contract lengths, and exit fees. Together, these charges fairly allocate costs to those causing them and incentivize large loads to reduce their impact on the grid from the first moment of site design. We also adopt an interconnection queue that will ensure a data center can only be energized once sufficient emissions-free generation is available to avoid hindering HB 2021 compliance. We have structured the queue to encourage load flexibility and innovative approaches to adding non-emitting capacity to the system through direct access, special contracts, or other arrangements between the customers and PGE.

Finally, recognizing that there are less direct impacts on the cost of equipment and energy required to serve all other customers when very large loads join the system, we institute a 1-cent per kilowatt-hour surcharge for Schedule 96 customers with 100 megawatts or more of allocated system capacity. Revenue from this surcharge will be used for non-cost effective energy efficiency (EE), repairs and distributed resource solutions to reduce energy burden for the most vulnerable customers.

II. BACKGROUND

The Commission opened this docket, an Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I, at the March 7, 2025 Regular Public Meeting. This investigation grew out of PGE's proposed modifications to its schedules and rules applicable to large load customers in docket UE 430. Specifically, Order No. 25-091 in that docket directed the Administrative Hearings Division to "open a docket and establish a procedural schedule 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." Docket UE 430 was itself an outgrowth of PGE's 2023 rate case, docket UE 416, in which the Commission adopted a partial stipulation under which the parties agreed to open an investigation to address new load connection costs.

Numerous parties intervened in this proceeding. Parties filed three rounds of testimony, followed by an evidentiary hearing conducted by the Commission on January 21, 2026. Amazon Data Services; the Alliance of Western Energy Consumers (AWEC); Climate

Solutions, Columbia Riverkeeper, Community Energy Project, Green Energy Institute at Lewis & Clark Law School, and Oregon Environmental Council (collectively, the Coalition); the Columbia River Inter-Tribal Fish Commission (CRITFC); the Oregon Citizens' Utility Board (CUB); the Data Center Coalition (DCC); Verrus; PGE; and Staff of the Public Utility Commission of Oregon filed opening and reply briefs.

III. FIRST STIPULATION

On February 4, 2026, PGE, Staff, AWEC, Amazon, the Coalition, DCC, and CUB submitted the First Partial Stipulation resolving a discrete set of issues in these proceedings. The Northwest & Intermountain Power Producers Coalition, Verrus, and CRITFC take no position on the First Partial Stipulation. The substantive terms of the First Partial Stipulation include:

1. Study Cost: Adopt PGE's Opening Testimony proposal to charge a flat fee for all studies for customers under 4 MW and allow changes to Rule I, Section 2 outlining the expiration period for study results (60 days unless extended) (PGE Exhibit 407).

2. Creation of Schedule 96: Adopt PGE's proposed framework for Schedule 96's rate design that includes: Purpose, Applicable, Monthly Rate, types of charges (basic charge, transmission and related service charge, distribution charges, system usage charge, and generation demand charge), as well as primary and subtransmission service levels.

3. Large Load Customer Agreement (LLCA) Threshold: Revise Rule I to lower minimum threshold for customers that require an LLCA to 20 MW.[1]

4. Load Following Credit: Do not extend Load Following Credit to Schedule 96 at this time. This resolves all Load Following Credit issues in this docket.

5. Substation Marginal Cost Study (MCOS): Update PGE's distribution MCOS to adopt PGE's Opening Testimony proposal to

[1] These are referred to as "Category 3" customers. "Category 2" customers are, under PGE's current tariff, from 1 MW to 30 MW. Category 2A customers do not require substation transformer upgrades while Category 2B customers do require substation transformer upgrades or have total Line Extension Costs greater than $1 million. "Category 1" customers have demand less than 1 MW and are generally not subject to rule changes in this proceeding.

calculate separate substation marginal costs by class to account for the significant differences in the way various customer classes use distribution infrastructure. (PGE/100, Ferchland-Barrow/16).

6. Queue Maintenance Costs: PGE will continue to allocate administrative costs associated with queue management under Rule I that are not assigned to an individual customer or applicant only to the rate schedules which utilize the queue.

7. Contributions in Aid of Construction (CIAC): Revise Rule I to allow any customer with an LLCA or [Minimum Load Agreements (MLAs)] to contribute up to 100 percent CIAC for non-shared distribution assets.

8. Allocation Claw Back: Adopt removal of "clawback" as described in PGE/200, Ferchland-Barrow/26 (lines 12-14) and make corresponding changes to Rule I, section 5, to implement its removal.

9. Site Aggregation: No changes will be made to the site aggregation definition in Rule I, section 1. This will resolve all issues related to site aggregation for this docket.

The Stipulating Parties submitted a joint brief in support of the stipulation.

IV. LEGAL BACKGROUND

PGE's revenue requirement was set in its most recent general rate case, docket UE 435, and Power Cost Adjustment Mechanism proceeding, docket UE 457, and is beyond the scope of the instant proceedings. This docket is concerned rather with the other primary step in ratemaking: allocation of the revenue requirement among the utility's customer classes.

As the proponent of its proposed tariff, PGE has the burden of proof. The phrase "burden of proof" has two meanings: one to refer to a party's burden of producing evidence; the other to a party's obligation to establish a given proposition in order to succeed.[2] To distinguish these two meanings, we refer to the burden of production and the burden of

[2] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-777 at 4, n 7 (Aug. 31, 2001) (citing *Hansen v. Oregon-Wash. R.R. & Nav. Co.*, 97 Or 190 (1920).).

persuasion.[3] ORS 757.210 establishes the burden of proof and provides that in a rate case "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is fair, just and reasonable." Thus, PGE must submit evidence showing that its proposed tariff and rates are just and reasonable. Once the company has presented its evidence, the burden of going forward (burden of production) then shifts to the party or parties who oppose the company's proposal.[4] Staff or an intervenor, if it opposes the utility's proposal, may in turn show that the proposed tariff or rate is not reasonable. For any tariff or rate proposed by PGE that is disputed by another party, PGE still must show, by a preponderance of evidence, that the proposal is just and reasonable. If the company fails to meet that burden, either because the opposing party presented persuasive evidence in opposition to the proposal, or because PGE failed to present adequate information in the first place, then PGE does not prevail because it has not carried its burden of proof.[5]

HB 3546 (2025), which was adopted after the initiation of this docket, sets out requirements with respect to the cost to serve "large energy use facilities," defined as "a facility that uses or is able to use 20 megawatts or more and is primarily engaged in providing a service described under the 2022 North American Industry Classification System Code 518210." The NAICS defines Code 518210 as "Computing Infrastructure Providers, Data Processing, Web Hosting, and Related Services."[6] This order refers to HB 3546's "large energy use facilities" as "large data centers" to distinguish them from the other large load facilities that have also been addressed by the parties. HB 3546 requires this Commission to provide for a "separate and distinct" classification of service under ORS 757.230, with its own tariff schedule, for large data centers. Any such schedule adopted by the Commission must either "[a]llocate the costs of serving the class of [large data centers] to the class in a manner that is equal or proportional to the costs of serving the class" or "[d]irectly assign the costs of serving a retail electricity consumer that is a large [data center] to the retail electricity consumer." The rate schedule must mitigate the risk of unwarranted shifting of costs to serve a large data center—including the electric company's costs to meet load requirements resulting from the provision of electricity service to the large data center—to other classes of retail customers, as well as the risk of other classes of retail electricity consumers paying unwarranted costs. In deciding whether to approve a proposed large data center tariff schedule, we must consider whether the rates result in, or have the potential to result in, increased costs or

[3] *See*, *e.g.*, ORS 40.105; ORS 40.115.
[4] *See In the Matter of the Application of Northwest Natural Gas Company for a General Rate Revision*, Docket No. UG 132, Order No. 99-697 at 3 (Nov. 12, 1999).
[5] *See In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB I 149*, Docket No. UE 116, Order No. 01-787 at 5-7 (Sept. 7, 2001).
[6] https://www.census.gov/naics/?input=51&chart=2022&details=51 (2022) (last visited Apr. 30, 2026) (linking to a scroll-down menu showing NAICS Code 518210).

unwarranted risk to other retail electricity consumers; whether they provide for equitable contributions to grid efficiency, reliability and resiliency benefits; whether they impede the electric company's ability to meet the clean energy targets set forth in ORS 469A.410[7] or reduce the emissions of greenhouse gases consistent with state policy; and whether they allow for procurement of, or contracts for, generation resources that support the electric company's ability to meet HB 2021's clean energy targets or reduce the emissions of greenhouse gases consistent with state policy, as well as whether they meet any other conditions we may require in the public interest.

An electric company providing service to a large data center must enter a contract with the large data center that "covers the provision of the electricity service, including, as applicable, transmission, distribution, energy, capacity or ancillary electricity services," and must meet several criteria, including, among others, that the contract specify the duration of the contract and be for at least ten years and that it obligate the retail electricity consumer to pay a minimum amount or percentage, as determined by the commission, based on the large data center's projected electricity usage for the electricity services the electric company is contracted to provide for the duration of the contract. The contract may also include a charge for excess demand for the electricity services the electric company is contracted to provide that is in addition to the tariff schedule.

V. DISCUSSION

A. Scope of Docket

1. Positions of the Parties

AWEC argues that the scope of this docket should be limited to large load data centers under HB 3546, stating that the underlying basis of this investigation relates to the amount of load growth in PGE's industrial rate schedules in recent years, and that based on evidence in the record, data centers are responsible for the majority of growth in these schedules. AWEC adds that because a data center rate class is required by HB 3546, limiting this proceeding to data centers is reasonable. AWEC raises concerns regarding whether PGE has met the legal notice requirements to other customer classes regarding a change in rates.

Staff and CUB note that the ALJ's memorandum adopting the issues list characterizes the core issue in this docket as "evaluating and appropriately allocating the cost to serve large customers * * *." PGE states that it was clear from the beginning that the scope of this

[7] HB 2021 (2021).

docket included all large load customers and, thus, that the docket could impact the terms of service for customers other than large load data centers under HB 3546.

2. Resolution

We decline to limit the scope of this proceeding to data centers under HB 3546. We note first that this investigation was opened before HB 3546 was passed and was applicable to large customers generally and to Rule C and Rule I. The Administrative Law Judge's May 20, 2025 ruling on the scope of the issues list in this proceeding characterized the core issue in this proceeding as "evaluating and appropriately allocating the cost to serve large customers." And the issues list gave notice that changes to cost allocation, which necessarily impact all customer classes, were within the scope of these proceedings. Accordingly, customers in Oregon had fair notice that this proceeding was intended to address large customer interconnections and cost allocation more generally.

Our goal in including Schedules 89 and 90, PGE's longstanding tariffs for large customer sites, in this proceeding is not to raise rates for those customers, but rather to continue to discipline costs and limit cost shifting between customer classes by re-structuring incentives for those unique loads to lower costs across the grid as a whole.

B. The Stipulation

1. Positions of the Parties

The Stipulating Parties submitted a brief in support of their stipulation. They state that overall, the stipulation is in the public interest and produces fair, just, and reasonable outcomes.

No party opposed the stipulation. Where there was disagreement on specific issues related to but not directly addressed by the stipulation, we have addressed that on an issue-specific basis below.

2. Resolution

Under OAR 860-001-0350, the Commission may adopt, reject, or propose to modify a stipulation. If the Commission proposes to modify a stipulation, the Commission must explain the decision and provide the parties with sufficient opportunity on the record to present evidence and argument to support the stipulation.

We review settlements on a holistic basis to determine whether they serve the public interest and result in just and reasonable rates. A party may challenge a settlement by presenting evidence that the overall settlement results in something that is not compatible with a just and reasonable outcome. Where a party opposes a settlement, we will review the issues pursued by that party, and consider whether the information and argument submitted by the party (which may be technical, legal, or policy information and argument) suggests that the settlement is not in the public interest, will not produce rates that are just and reasonable, or otherwise is not in accordance with the law. To support the adoption of a settlement, the stipulating parties must present evidence that the stipulation is in accordance with the public interest, and results in just and reasonable rates.

We have reviewed the stipulation and supporting brief entered into by PGE, Staff, AWEC, Amazon, the Coalition, DCC, and CUB. We find that the terms of the stipulations are supported by sufficient evidence, appropriately resolve issues in this proceeding, and will result in fair, just, and reasonable rates that are consistent with the requirements of the POWER Act. We determine that the terms of the stipulation, taken together, represent a reasonable resolution of the identified issues and contribute to an overall settlement in the public interest. Accordingly, we adopt the stipulation.

C. Schedule 96 and Other Associated Changes

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

a. Positions of the Parties

The Stipulating Parties agree that we should "[a]dopt PGE's proposed framework for Schedule 96's rate design that includes: Purpose, Applicable, Monthly Rate, types of charges (basic charge, transmission and related service charge, distribution charges, system usage charge, and generation demand charge), as well as primary and subtransmission service levels."[8] Schedule 96, as proposed, defines service for the loads described in HB 3546:

> To each Large Nonresidential Customer whose Demand has exceeded 20,000 kW or has a contract for demand of 20,000 kW or greater within their site point of delivery who is engaged directly in providing a service described under code 518210 of the 2022 North American Industry

[8] First Partial Stipulation at 2, paragraph 3.

> Classification System ("data center services") or who is indirectly related as a landlord with tenants engaged in providing data center services.[9]

CRITFC believes additional protections are necessary, including (1) adequate cost allocation to protect other customer classes, (2) standards to improve data center grid performance, (3) direct investment in efficiency programs and other benefits for vulnerable communities, (4) transparent impact reporting in line with HB 2021 and HB 3546 public interest goals, and (5) utility-tribal consultation to discuss and mitigate cumulative impacts to reserved rights, resources, and sovereign prerogatives.

b. Resolution

As noted above, we accept the Stipulation which would have us adopt PGE's proposed framework for Schedule 96's rate design that includes sections addressing purpose, applicability, monthly rate including types of charges (basic charge, transmission and related service charge, distribution charges, system usage charge, and generation demand charge), as well as primary and subtransmission service levels. The proposed Schedule 96 framework meets the statutory requirement that we establish a "classification of service" for large data centers that is "separate and distinct from classifications of service for other commercial or industrial retail electricity consumers and have its own tariff schedule."[10] We find that the Stipulating Parties' proposed framework for Schedule 96's rate design is appropriate for creation of a new rate schedule.

While many of CRITFC's recommendations extend beyond the creation of a new rate schedule we consider each of their proposals below. Cost allocation is addressed throughout the order, but particularly in sections on the Peak Growth Modifier (Section C(6))). Investment in EE is addressed in Section C(3). Reporting requirements are addressed in Section I, and standards for data center performance and tribal consultation are addressed in Section J.

[9] PGE/410 Ferchland-Barrow-Jose/1, Portland General Electric Company P.U.C. Oregon No. E-19 Original Sheet No. 96-1.
[10] HB 3546 § 2(2) (2025).

2. 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?

a. Positions of the Parties

Verrus proposes that the Commission approve a subclass of customers within Schedule 96, which Verrus has termed Schedule 96-F, as part of this docket, which would apply to data centers that have what Verrus calls "asset-backed facilities" resulting in flexible loads. Only those loads that meet specific eligibility criteria, including the ability to curtail the greater of 20 MW or 25 percent of peak load, would qualify to take service under the Schedule 96 subclass. In order to ensure that asset-backed flexible loads do not subsidize other data centers, Verrus argues that PGE's proposed Peak Growth Modifier (PGM) should be adjusted for the subclass to reflect the flexible load customer's net contribution to system peak (after verified curtailment). Verrus states that customers electing Schedule 96-F would submit an annual flexibility plan detailing curtailment commitments and telemetry data access that meets or exceeds defined minimums established at the time of interconnection. PGE would evaluate compliance each year, and customers would need to demonstrate verified performance in order to remain on Schedule 96-F. If a customer did not meet this requirement, it would revert to the standard Schedule 96 for at least three years.

PGE believes that there is not sufficient information available in this docket to support the formation of a subclass of customers at this time and asks that the Commission instead direct PGE to study data center flexibility in its next general rate case to determine if a flexible subclass of Schedule 96 or alternative mechanism to recognize customer flexibility is needed.

Staff supports investigating how the benefits or unique characteristics of data centers with asset-backed flexible loads should impact cost allocation and other issues addressed in this docket. However, Staff does not believe the record is sufficiently developed to implement alternate provisions for data centers with flexible load, and accordingly, supports investigating alternate provisions for data centers with flexible load in a subsequent phase in this docket or a separate proceeding immediately following the conclusion of this docket.

CUB generally supports a flexible data center subclass within Schedule 96 but does not believe the details have to be determined in this docket. CUB would support having PGE propose criteria, with stakeholder input, for defining flexible data centers and a cost allocation methodology that recognizes the difference in cost between flexible and

inflexible load, which CUB states could be done in an additional phase of this docket or in PGE's next rate case.

The Coalition states that while a subclass of flexible customers may be warranted in the future, the record in this docket is not sufficiently developed to create such a subclass at this time. Similarly, Amazon does not believe that such a subclass should be created as part of this docket based on the current record.

The DCC is not opposed to establishing a subclass within Schedule 96 for flexible loads.

b. Resolution

We extensively explored this issue during the January 21, 2026 hearing, seeking to understand intervenors' proposals for the most efficient and effective path to mitigating overall cost and reliability pressure large loads may create by incentivizing or at least valuing flexibility.[11] We find the opportunities for valuable flexibility are unique and complex, shaped by the particular locational constraints and other characteristics of each large load. As a result we decline to create a subclass for flexible loads and we also decline to devote Staff resources to an additional, subsequent investigation at this time. It is unclear on this record that a single approach applied to a subclass will accomplish the desired result. And we are conscious of limited Staff resources going forward.

However, we do believe that flexible data centers may bring benefits to the grid and that it would be appropriate to recognize those benefits as a credit in special contracts. We will consider those benefits and credits when they are brought before us in special contracts. That will allow the characteristics of individual data centers to be considered on a case-by-case basis, which we deem more appropriate than creating class-wide policy based on the limited record before us. Additionally, we seek through our decision-making below to incentivize flexibility where it adds value.

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

a. Positions of the Parties

CRITFC argues that a surcharge for non-cost-effective EE is a pragmatic way to ensure the costs and risks of large data centers are mitigated and offset to protect other customer classes and environmental justice communities, as defined under Oregon law.

[11] Hearing Transcript at 13-19.

The Coalition supports applying a surcharge of 1 cent per kwh to Schedule 96 customers with an Allocated System Capacity of 100 MW or greater. The Coalition notes that customers that have an Allocated System Capacity of 100 MW and load factors of 80 percent would exceed the HB 3141 cap on contributions to cost-effective EE and the public purpose charge, and argues that these very large data centers should be required to contribute additional funds towards non-cost-effective EE and enabling repairs for low-income customers to help mitigate the energy burden for those customers and offset some of the load growth impact of the data center. The Coalition argues that its proposal is distinct from the statutory public purpose charge (PPC) because it lacks two unique characteristics of the PPC: first, while the PPC is structured as a sales tax in that it is measured as a percent of the revenues (sale price) of the customer's bill, the Coalition's proposed surcharge would be assessed on a per-kWh basis. And second, while some PPC funds are used for non-energy-related purposes such as low-income housing, the proposed surcharge would be used exclusively for the acquisition of non-cost-effective EE and enabling repairs.

Staff does not support the proposed surcharge, but does support working with parties to develop an optional payment structure to Energy Trust of Oregon (ETO) for non-cost-effective EE and DSM.

PGE urges the Commission to reject the proposal of CRITFC and the Coalition, arguing that the record does not demonstrate a non-cost effective EE directed tariff surcharge is warranted, and adding that such a charge would be duplicative because pursuant to ORS 757.054, PGE collects funds on behalf of the ETO that are used for EE measures and distributed generation in a separate schedule—Schedule 109—from which Schedule 96 customers will not be exempt.

AWEC also opposes the proposal, arguing that it exceeds the requirements of a data center rate class in HB 3546 and is undeveloped, in that CRITFC's initial proposal did not identify the amount of the surcharge it proposes, the amount likely to be collected, the level of need the surcharge would address, or made any persuasive argument that utility ratepayers should fund these investments given that they will not be cost-effective and, thus, would not benefit ratepayers. According to AWEC, CRITFC's proposal implicates broader public policy issues that are best addressed by the Legislature. Amazon similarly opposes the proposal. The DCC opposes creating any new surcharges specific to large load data center customers in Schedule 96. The DCC also objects to what it terms "[e]fforts to modify or reinterpret the PPC,"[12] although it is not clear whether this characterization relates to the proposal discussed in this section, the proposal discussed below to require all Schedule 96 customers to pay the statutory maximum for

[12] DCC Closing Brief at 8.

cost-effective EE, or both. The DCC notes that "ORS 757.6612 [*sic*] establishes the PPC as a fixed, legislatively prescribed charge and expressly provides that the Commission 'may not establish a different public purpose charge' than one created by statute."[13]

b. Resolution

A load of 100 MW or more places unique burdens on the system and thus on other customers that, while difficult to quantify, are nevertheless real. While the specific costs of serving a new load can be identified with some precision, the degree to which new, very large loads are raising costs across the region by utilizing relatively scarce clean energy generation projects or limited transmission capacity is difficult to isolate. We find that applying a surcharge of 1 cent per kWh to Schedule 96 customers with an Allocated System Capacity of 100 MW or greater to fund non-cost-effective EE, critical home repairs (also called "enabling repairs"), or distributed energy resources (DER) to insulate energy burdened customers, is a reasonable means of mitigating some of that impact and helping mitigate cost shifting to residential customers. Reducing energy burden serves to reduce a host of other costs, such as arrearages and the cost of low-income differentiated rates, better mitigating the overall cost shifting impact through these revenues.

That the funds collected through the proposed surcharge would be used to benefit the public does not render the surcharge an impermissible additional public purpose charge. While there is no statutory definition of a public purpose charge, as the Coalition notes, both the structure of the surcharge and the use of the funds distinguish it from the statutory public purpose charge.

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

a. Positions of the Parties

PGE proposes that Schedules 89 and 90, their long-standing large load tariffs that apply to non-data center large customers,[14] be revised to include a demand charge for large industrial customers for fixed generation recovery in place of a volumetric charge. PGE argues that expanding this rate design structure, which currently applies only to

[13] *Id.*, n 16 (quoting ORS 757.612(3)(h)).
[14] Large Nonresidential (>4,000 kW) Standard Service (Schedule 89) and Large Nonresidential Standard Service (>4,000 kW and Aggregate to >30 MWa) (Schedule 90). We note that the demarcation line between Schedules 89 and 90 is not the same as that between Categories 2B and 3; it is possible for a Category 3 customer to be on Schedule 89.

Schedules 83[15] and 85,[16] to other large commercial and industrial schedules will create design consistency for customers who migrate rate schedules as they grow. Staff supports PGE's proposal, which Staff states will provide consistency across the industrial rate classes and provide price signals reflective of system costs to Schedule 89 and 90 customers.

As addressed above, AWEC recommends this docket be limited in scope to Schedule 96, the new schedule proposed for large data centers. AWEC states that its recommendation is intended to foreclose rate design issues for Schedules 89 and 90 and suggests that any rate design issues regarding Schedules 89 and 90 should be addressed in a general rate case.

b. Resolution

We adopt PGE's proposal. We find that it is just and reasonable to transition Schedules 89 and 90 to a demand charge. We also find, as discussed above, that there was ample notice that this docket would concern all large load customers and therefore that this is an appropriate venue to make this change. We find that implementing a demand charge for these customers will create rate design consistency amongst the large commercial and industrial schedules and provide price signals reflective of system costs for these customers.[17]

Consistent with our explanation above, this change is not intended to increase rates for the affected schedules, but rather to re-structure the incentives for these rate classes: The change from volumetric to demand-based charges is intended to be revenue neutral for Schedules 89 and 90.

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

a. Positions of the Parties

The Coalition supports requiring Schedule 96 customers to pay the maximum contribution allowable under HB 3141. According to the Coalition, under HB 3141, customers with an annual energy usage of 10 aMW or more cannot be required to pay more than $4 million dollars combined to the public purpose charge and for cost-effective EE per year. However, based on current rates, customers only reach that cap after using

[15] Large Nonresidential Standard Service (31-200 kW).
[16] Large Nonresidential Standard Service (201-4,000 kW).
[17] PGE/100, Ferchland-Barrow/37; Staff/300, Stevens/51.

about 80 aMW, or the equivalent of a customer with an Allocated System Capacity of 100 MW and an 80 percent load factor. The Coalition thus believes that significant headroom exists for data center customers to pay more towards EE measures that could help offset the load growth that data centers bring to PGE's system. CRITFC supports the proposal.

Staff states that it generally agrees that customers above 20 MW should pay the maximum allowed under ORS 757.054 and ORS 757.612 because their size will likely be at or near the cost cap regardless. However, Staff recognizes there could be situations where a customer fails to scale up to their projected demand but is paying minimum demand costs based on a much larger projected load. To avoid burdening customers in this scenario, Staff recommends that customers at or above 20 MW pay the combined maximum allowable for cost-effective EE under ORS 757.054 and ORS 757.612 if the customer's current generation or transmission demand is at least 90 percent of the forecasted demand. If the customer's actual generation or transmission demand is less than 90 percent of forecasted demand, then Staff proposes that the customer simply pay the typical rates for the class and according to ORS 757.054 and ORS 757.612.

CUB states that it supports the proposals of the Coalition and Staff.

PGE opposes requiring all Schedule 96 customers to pay the maximum contribution allowable under HB 3141. According to PGE, ORS 757.054 Section 3(3) sets forward specific dollar limits to EE funding based on the size of the customer; applying the maximum amount allowable would result in data centers paying distinctively different and higher costs to fund EE than other customer classes, including other large industrial customers. PGE states that it understands funding concerns for EE as put forth by CUB and has shifted its position to support a methodological adjustment reflecting the residential investment in system-wide EE when forecasting class coincident peaks for generation and transmission cost allocation. PGE believes that this adjustment will enable terms that do not compromise fairness, in contrast to the suggestion that Schedule 96 customers should pay a disparate amount. AWEC similarly opposes requiring Schedule 96 customers to pay the maximum contribution, stating that it could dramatically increase affected customer rates by changing how EE costs are allocated to the data center rate class, and arguing that there is no evidence in the record justifying outlier treatment. The DCC argues that the charges required by HB 3141 are not within the scope of this proceeding, and thus, should not be amended in this case. As noted above, the DCC also objects to what it terms "efforts to modify or reinterpret the PPC,"[18] although it is not clear to which proposal this objection relates.

[18] DCC Closing Brief at 8.

b. Resolution

There is conflicting evidence in the record regarding the peak demand and capacity factor at which a customer would be likely to reach the statutory cap of $4 million per year under HB 3141. Under either Staff's or the Coalition's interpretation of those facts, however, we find it reasonable to require all Schedule 96 customers to contribute the maximum amount allowable under HB 3141, including during scale up. Increasing the funding for cost-effective EE and other programs funded by the public purpose charge will protect the public interest and "provide for equitable contributions to grid efficiency, reliability and resiliency benefits" consistent with the POWER Act[19] by helping to counterbalance the difficult-to-quantify negative externalities that data centers impose on the system. Schedule 96 is a distinct statutory and tariff classification, created under the POWER Act. Requiring that all Schedule 96 customers contribute the maximum under the cap ensures that all Schedule 96 customers are treated the same under this statutorily directed, separate rate class. We find that the approach adopted here results in just and reasonable rates and is a reasonable condition in the public interest to require for Schedule 96 consistent with the POWER Act.

We understand the Coalition and CUB's concerns that the limitations described in ORS 757.054 Section 3(3) could lead to large customers contributing proportionally less to cost effective EE than residential customers. We agree that for the largest Schedule 96 customers, our ability to direct such contributions in proportion to customers' energy use is constrained by the statutory limitation of $4 million per year.

6. The Peak Growth Modifier and its Alternatives

a. Positions of the Parties

PGE advocates for allocating fixed generation and transmission costs based on class contribution to system peak through a new calculation, which it calls the peak growth modifier (PGM), that includes allocation of growth-related investments to the customer classes most responsible for increasing the system's peak demand. PGE describes its approach as an evolution from existing coincident peak methodologies that better reflects current system dynamics. This in turn will allow for differentiation between growth and non-growth fixed generation in order to improve allocation of those costs among customer classes. PGE proposes a three-year backward-looking window, increasing to ten 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). According to PGE, this is an appropriate amount of

[19] HB 3546 § 2(3)(b).

time to limit the assignment of growth-related costs. PGE states that starting with a three-year period and extending 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.

Staff recommends that the Commission adopt PGE's PGM with certain modifications. First, Staff would make allocations indefinite rather than limited to ten years as PGE proposes. Allocations would be subject to change if evidence showed the facility is no longer used to serve growth. Staff believes this fact-based method is more sound than simply assuming all growth-related resources will become system resources after ten years have elapsed. Staff also advocates for clear criteria defining "growth-related" assets and specifying when these assets should be included in the Test Year load forecast. Staff argues that the Test Year load forecast should be included in the PGM. Staff urges the Commission to reject PGE's proposal[20] to provide negative PGM credit to customer classes that are decreasing in load, arguing that while these customers should not be allocated any growth-related costs under the PGM, they would already be allocated less of the costs of the existing system under PGE's current cost allocation methodology, which would reflect their decreasing capacity needs.

Staff recommends situs assignment of local transmission projects to large load customers to the extent it is determined that load growth from large customers is the primary driver for acquiring the asset. For costs of growth-related transmission assets that are not situs assigned, Staff supports PGE's PGM subject to the qualifiers discussed above. Staff also does not support CUB's proposal to assign non-local transmission to large load customers. Staff's modified PGM proposal would link recent load growth to regional transmission investments proportional to each class's growth. Staff believes this method will be sufficient for assets that do not have a direct geographic link to new large customers.

Staff states that it supports assignment of growth-related costs to all customer classes through an allocator like the PGM. However, Staff does not support direct assignment of such costs to smaller customer classes.

CUB supports two approaches that it says work together. First, when a generation resource is clearly connected to the growth of data center load, it should be directly assigned to the individual data center or to the data center class. Second, where new generation supports load growth across customer classes, it should be assigned to the

[20] *See* Coalition/300, Souder/36, n 55 (citing Coalition/305, Souder/1, PGE Response to OPUC Data Request 22, stating that "[r]ate classes with negative growth during the 3-year window will receive an offsetting credit against the non-growth costs that are allocated on the basis of the relevant generation or transmission marginal cost study.").

classes with growing loads, after accounting for EE investment. This could mean allocating the incremental cost of generation necessary to serve load growth to the customer classes based on the load growth of that class. CUB does not support PGE's proposed approach to generation allocation, which CUB states has the same arbitrary and concerning time limitations that PGE also proposes for transmission investments. CUB states, however, that generation assets have long useful lives, and there could be reasons in the future why this no longer makes sense, particularly with individual investments. Since MCOS and resource allocations are reviewed in each general rate case, facts that require revisiting a prior allocation can be reviewed and revisited. CUB believes that this is a more reasonable and fact-based approach than PGE's PGM and provides flexibility for changed circumstances that is missing from Staff's approach.

CUB argues that data centers should be allocated the marginal cost of transmission, with the remaining transmission revenue requirement assigned to other customer classes, divided proportionally. CUB states that rather than socialize the transmission costs of new load across all customer classes, PGE should recognize that data center load is the primary source of load growth and will continue to be into the foreseeable future, and assign the cost of data center load growth to data centers. If the Commission rejects this approach, CUB recommends that transmission costs that are incurred primarily to serve large customers should be directly assigned to large customers. CUB states that transmission that is growth related but not directly assigned would be assigned based on the growth in customer classes after recognizing the impact of EE, similar to CUB's proposal regarding fixed generation. CUB is concerned that under Staff's proposal, the costs of non-local transmission associated with new generation will simply be rolled into the transmission revenue requirement and raise the rates for all customers. CUB states that this outcome would not be in line with HB 3546's intention to mitigate unwarranted costs and cost shifting from large load customers to other customers.

CUB asks the Commission to reject PGE's proposal to limit the assignment of costs to data centers or other growing load to a three- to ten-year period as CUB believes that this approach results in continued cross subsidization. CUB states that the initial cost assignment of growth-related investments that are directly assigned to customers or allocated based on a growth-related allocation methodology should remain until there is evidence that this no longer represents how they are being used. Similarly, the Coalition argues that the assignment of growth-related costs should not be time limited; instead, growth-related costs should remain allocated to the rate class causing growth as long as the asset continues to serve growth-driving customers.

AWEC cautions the Commission against adoption of growth-based allocation of generation and transmission costs without additional analysis to support such allocation

as it would constitute a paradigm shift. AWEC is concerned that growth-based cost allocation may harm existing customers and have unintended consequences. If the Commission determines that a growth-based cost allocation is nevertheless appropriate, AWEC argues that it should be limited in its application in this case to Schedule 96 and the impacts to other customer classes should be deferred until PGE's next rate case, adding that if the Commission determines that growth-based allocation should be applied more broadly to other customer classes, the model should treat the growth of all customer classes similarly and be applied systemically across time. AWEC raises a concern regarding mismatched timing of growth and capital expenditure. AWEC asserts that the majority of PGE's recent transmission buildout has focused on accommodating future load growth that is expected to ramp over a period of several years, and that this means that the load responsible for these costs has not yet materialized. AWEC warns that this timing mismatch can cause pernicious and unintended impacts in certain situations.

The Coalition supports allocating fixed generation and transmission for growth-related assets using PGE's proposed PGM but states that resources categorized as growth-based should remain in the PGM indefinitely, unless PGE makes a specific showing that a given resource is no longer necessary to serve growth. Additionally, the Coalition argues that growth should consistently be measured against a fixed point in time that the Commission establishes. The Coalition has proposed January 1, 2025, as that fixed point in time. Alternatively, the Commission could set the point in time as the used and useful date of the oldest resource in the PGM.

CRITFC states that it supports full cost assignment for all resources used by the class of large load customers.

Amazon states that the costs of assets that are built for the system should be allocated based on cost-of-service billing determinants.

The DCC asserts that PGE should refrain from adopting the PGM in this case and instead maintain the status quo to avoid unintended consequences. If the Commission adopts PGE's PGM, which the DCC opposes, the DCC argues that the Commission must maintain consistent policies over time irrespective of shifts in customer growth to avoid allowing the PGM to be used to manipulate certain rate outcomes (*i.e.*, to consistently reduce residential rates).

Staff supports inclusion of the test year load forecast in the PGM. Staff believes that doing so would better capture the sequencing of procurement to serve anticipated load growth and prevent by cross-subsidization and cost shifting including near term forecasted load growth in the PGM.

CUB recommends that before assigning costs related to growth, the PGM must be adjusted to recognize the EE resource that has been purchased by residential or other customers in excess of their needs and the time limitations for cost-allocation removed. In addition, CUB believes that costs that are more appropriately directly assigned should be removed.

b. Resolution

We find the PGM will fairly allocate costs of growth to the classes of customers responsible for that growth and thus will prevent cost shifting, improve fairness in cost causation, and uphold customer understanding and administrative simplicity.[21] We find the PGM will support more sustainable and equitable rate structures across all customer classes.[22] However, we adopt Staff's, CUB's, and the Coalition's proposals to make allocations to the PGM indefinite, rather than from 3 to 10 years, as proposed by PGE.[23] By indefinite, we mean that a growth-related asset will remain in the PGM until it is demonstrated that system usage no longer supports the allocation. We find that this combination—of the PGM with indefinite allocations—will most fairly allocate growth-related investments among the customer classes. We find that this will align with the POWER Act's directive that requires utilities to protect against cross-subsidization of large data centers. We also find that by avoiding unwarranted cost shifting, and by aligning cost allocation with cost causation, the PGM will benefit the system as a whole, not just one customer class or rate schedule.[24] We note that this approach will require PGE to track consecutive vintages of assets with different allocation percentages.

We do not adopt the Coalition's proposal to measure the PGM from a fixed point in time, finding that over time, it may cause allocation of investments to classes that are no longer responsible for load growth. Further, the prudence of incremental capital investment is generally reviewed in a general rate case, so the allocation of that incremental investment should also be based on an incremental approach.

We agree with Staff that the test-year load forecast should be incorporated into the PGM. We agree that doing so will better align with the sequencing of procurement to serve anticipated load growth and prevent cross-subsidization and, as the record shows, will avoid a mismatch between the timing of customers coming online and when capital is placed into service.[25]

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[21] PGE/100, Ferchland-Barrow/15.
[22] PGE/100, Ferchland-Barrow/19.
[23] *See* Staff/500, Stevens/10; CUB/300, Jenks/13; Coalition/400, Souder/30.
[24] *See* PGE/100, Ferchland-Barrow/13.
[25] Staff/500, Stevens/12.

We do not incorporate EE into the PGM at this time, finding that to be a larger effort that needs additional record development. We discuss below CUB's general recommendation that EE be incorporated into the MCOS study and our encouragement to CUB to bring that issue to PGE's next general rate case. At that time, it may be appropriate to incorporate EE into the PGM as well.

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

a. Positions of the Parties

AWEC proposes that weather should be modeled to reflect 1-in-20-year weather conditions in both the base year and the growth year, to ensure that the extra capacity necessary to serve weather sensitive loads is properly captured in cost allocations.

Staff and CUB support AWEC's proposal. The DCC agrees that weather normalization will result in more accurate costs but believes that it should be reviewed in a rate proceeding.

PGE describes AWEC's proposal as redundant, asserting that 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, PGE says, system peak growth is determined as the difference between forecasted peaks under normal weather conditions.

b. Resolution

We accept AWEC's proposal for weather normalization, finding that weather should be modeled to reflect 1-in-20-year weather conditions in both the base year and the growth year. We agree with AWEC that this will ensure that the extra capacity necessary to serve weather-sensitive loads is properly captured in cost allocations,[26] resulting in just and reasonable rates that avoid cross-subsidization.

[26] AWEC/200, Kaufman/11:3-5

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

a. Positions of the Parties

PGE proposes a definition of growth-related investments or assets: "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."[27] PGE lists several examples of what it terms growth-related transmission and generation investments, as well as examples of investments that it would not consider growth-related.[28]

Staff believes PGE's modified methodology for identifying growth-related investment is an improvement in that it is more specific than PGE's original proposal. However, Staff does not think PGE's criteria capture all potential load-growth investment; Staff accordingly proposes an addition to the list of examples of growth-related transmission investments: "Transmission projects which are triggered by new or additional loads causing the company to be subject to more stringent planning or reliability standards."[29] Staff remains concerned, moreover, by the subjectivity of PGE's approach. As an alternative, Staff recommends a more objective methodology, such as a criterion that allocates growth-related investments based on recent capacity additions and load growth. Staff recommends that whichever method the Commission chooses be seen as a flexible starting point and subject to change in future proceedings.

AWEC advocates for defining "growth-related" investments or assets clearly and based on objective criteria that ensure non-discriminatory treatment. AWEC does not have specific criteria in mind and states that it is unsure how such criteria would be developed.

CUB expresses concern that PGE's proposed methodology is based on PGE's own determination of what investments are considered growth-related, noting that PGE has long claimed that transmission investments support the entire system, not individual loads. CUB believes that PGE's assessment that costs such as those associated with the Hillsboro Reliability Project are "system costs" not attributable to the growth of data centers in Hillsboro foreshadows how PGE will determine what it believes are "growth-related" investments to include in the PGM going forward.

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[27] PGE Opening Brief at 41.
[28] PGE Opening Brief at 41-43.
[29] Staff Opening Brief at 14.

The Coalition argues that the Commission should provisionally adopt the definition of "growth-related" that PGE proposed in Surrebuttal Testimony, with one change to indicate that a resource be categorized as growth-related if it "would not be required at this time or scope," rather than PGE's proposed "time and scope." The Coalition states that it understands "scope" to mean size. The Coalition also recommends that the company hold workshops in 2026 where it explains and receives feedback on the analyses the company will perform to make its determinations, to provide insight for Staff and other parties about the ways PGE is evaluating its investments to ensure that projects are properly categorized moving forward. The Coalition expresses agreement in principle with the types of assets PGE identified as growth-related in its Surrebuttal Testimony.

The DCC states that if the Commission adopts PGE's PGM, which the DCC believes the Commission should not, it must maintain a consistent definition for "growth-related" investments to avoid allowing the PGM to be used to manipulate certain rate outcomes.

b. Resolution

We adopt PGE's framework for determining whether investments are load growth-related, as modified by Staff. Transmission investments will be considered growth-related based on whether they are triggered by new or increasing load; generation investments will be considered growth-related when they are triggered by the need for incremental capacity or energy to reliably serve increased demand. We view this as a reasonable starting point, and agree with PGE that "clear guidelines are important and that transparency around how growth and non-growth assets are defined is essential to ensuring consistent and well-understood application."[30] We also acknowledge Staff's caution that it might ultimately spark an inefficient amount of litigation in rate cases when PGE brings these assets into service. We do not, however, believe that there is sufficient evidence in the record to develop the criteria under Staff's alternate proposal. We will continue to evaluate the method adopted today as it is applied in future proceedings and will consider changes should a party bring forward more objective criteria at that time.

[30] PGE/400, Ferchland-Barrow-Jose/25.

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

a. Positions of the Parties

According to CUB, residential households more than offset their load growth through investing in EE for other classes of customers. CUB states that the record shows that residential customers fund 60 percent of ETO investments, while only 40 percent of ETO costs serve residential programs, and that the record also shows that the increase in EE savings that residential households are funding is primarily coming from commercial and industrial customers. CUB notes that residential customers are not getting credit for this EE investment in the MCOS study because the MCOS limits marginal resources to renewables and batteries. CUB recommends that EE be counted as a marginal resource in the MCOS, arguing that customers who fund EE outside of their property or their rate class should see recognition of the role this EE investment has in avoiding investments in more expensive new resources. CUB notes that this is not just a residential issue but could be a way for data centers to invest in resources to meet their loads.

PGE states that while EE does not automatically factor into the MCOS allocation and thus was not included in PGE's initial proposal in this docket, PGE acknowledges that, in addition to the system benefits of EE, there are participant benefits for those customers receiving EE within ETO programming. Specifically, EE participants have lower energy demand than they otherwise would, which impacts their class's contribution to system peaks and allocated generation and transmission costs. PGE says that in response to CUB's EE funding concerns it has shifted its position to be supportive of a methodological adjustment that reflects the residential investment in system-wide EE when forecasting class coincident peaks for generation and transmission cost allocation. According to PGE, this adjustment would spread coincident-peak reductions achieved by ETO based on funding by customer class, which will allow appropriate accommodation for EE.

The Coalition supports CUB's proposal that customer classes receive the benefit of load reductions from EE for which they pay. If a customer class pays for more EE than ETO acquires for that class, the paying class is subsidizing the EE of other classes. Those other classes would then receive the benefit in the PGM of the prevented growth, as they would be allocated a relatively smaller share of the cost of the resources in the PGM.

Staff believes CUB's proposal to include EE in the MCOS is out of scope for this case. Staff argues that the question of whether EE is appropriately treated as a supply side resource in the MCOS is not primarily related to large customer loads but more generally

to how generation costs should be allocated. However, Staff states that it is open to exploring how EE costs are allocated in PGE's next rate case.

AWEC argues that the Commission should not incorporate EE into the MCOS. AWEC raises three concerns regarding CUB's proposal and PGE's refinement of it. First, the data CUB and PGE rely on from the ETO divide EE funding and impacts between residential and non-residential customers only, and do not distinguish between different classes of non-residential customers. Second, CUB's and PGE's proposals are based on energy savings rather than spending levels. Because EE is cheaper to acquire from large customers, AWEC believes that these parties' analyses are misleading in terms of how funding for EE is allocated. Third, AWEC states that CUB's and PGE's proposals would result in additional allocations of EE costs to non-residential customers, and that for customers that are at the legislatively mandated cap, these additional allocations would violate Oregon law.

DCC states that it strongly opposes making changes to EE in this proceeding.

b. Resolution

We agree with Staff that revising the MCOS to incorporate EE as a supply side resource is out of the scope of this case, not being intrinsically related to large load customers, and do not adopt it here. We encourage CUB to raise this issue in PGE's next general rate case, where the issue will be in scope and can be considered more holistically.

10. Should changes be made to the marginal cost study for distribution?

a. Positions of the Parties

The Stipulating Parties agreed that PGE should "[u]pdate [its] distribution [MCOS] to adopt PGE's Opening Testimony proposal to calculate separate substation marginal costs by class to account for the significant differences in the way various customer classes use distribution infrastructure."[31]

Separately, CUB argues that the Commission should order PGE to conduct a study to identify which elements of the distribution system provide system benefits by supporting programs like the Virtual Power Plant (VPP) and DER, and in its next general rate case, propose a new distribution allocation methodology that recognizes these system benefits.

[31] First Partial Stipulation at 2, paragraph 6.

Staff recommends that a class-wide distribution O&M charge should be calculated for Schedule 96. Staff states that it supports CUB's proposal to spread costs of distribution upgrades used to reduce generation costs and recommends adopting PGE's substation marginal cost changes.

AWEC states that except as agreed to by the parties in the stipulation, the Commission should not change how distribution costs are allocated to customer classes in this docket other than for Schedule 96.

b. Resolution

As discussed above, we adopted the stipulation, including that PGE should "[u]pdate [its] distribution MCOS to adopt PGE's Opening Testimony proposal to calculate separate substation marginal costs by class to account for the significant differences in the way various customer classes use distribution infrastructure."

We agree with CUB that the interaction between distribution system costs and the benefits and costs of programs like VPP and DER could reasonably impact cost allocation across customer classes, as other uses of the distribution system do. PGE's next distribution MCOS should address this issue.

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

a. Positions of the Parties

CUB argues that distribution assets should not be included in rate base until the applicant for which the assets are built comes online. CUB notes that PGE makes these investments in anticipation of the data centers coming online, often two years before the data center is actually online. CUB asserts that these investments were made to serve specific customers and should not be considered used and useful and should not be included in rate base until the new customer is utilizing them. Staff supports CUB's proposal.

PGE argues that the Commission should reject CUB's proposal. According to PGE, the generally applicable framework—in which distribution assets placed in-service pursuant to Commission-approved planning assumptions, connected to PGE's system and determined to be prudent are used and useful and not excluded from rates—reflects the Commission's current regulatory policies and the legal requirement that only assets that are used and useful may be included in rates. PGE does not believe that there is a legal or

evidentiary basis for changing this framework to exclude from rates costs that were prudently incurred for assets that are used and useful.

The DCC opposes any changes to the Commission's used and useful requirement, adding that if any changes are adopted, they should apply to all customer classes.

b. Resolution

Oregon's "used and useful" law, ORS 757.355, provides:

> [A] public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.[32]

Oregon courts have settled that the statute "precludes the PUC from allowing rates * * * that include a rate of return on capital assets that are not currently used for the provision of utility services."[33]

We are concerned that under some circumstances, putting equipment into rates well in advance of energization of the data center it is meant to serve could violate the used and useful standard. We decline to opine further in the theoretical and expect that this issue will be addressed in the rate case in which PGE seeks to recover from assets it asserts are used and useful.

[32] ORS 757.355(1).

[33] *Citizens' Util. Bd. of Oregon v. Pub. Util. Commn. of Oregon*, 154 Or App 702, 712, 962 P2d 744, 752 (Or App 1998) ("Trojan I"); *see also Gearhart v. Pub. Util. Commn. of Oregon*, 299 P3d 533, 541 (Or App 2013), *aff'd*, 339 P3d 904 (Or 2014); *see also Pacific Power & Light Co. v. Department of Revenue*, 308 Or 49, 53-54, 775 P2d 303, 306 (1989) ("When a utility constructs new property, such as a generating facility, that property is not included in the utility's rate base until it actually is placed in service and, even then, the regulators may not allow it in the rate base until the utility establishes that the property is reasonably necessary to provision of electrical service").

12. Should the Commission direct PGE to complete a "but for" analysis in its next Clean Energy Plan/Integrated Resource Plan?

a. Positions of the Parties

Staff recommends that the Commission direct PGE to complete a "but for" analysis in its next Clean Energy Plan (CEP)/Integrated Resource Plan (IRP) to give the Commission and stakeholders a qualitative understanding of the impact of large load customers on the company's generation and transmission planning decisions and related costs. Staff states that such an analysis would also serve as a check for the reasonableness of the generation MCOS and rate spread derived from it. Staff proposes that this analysis would not be used to directly spread generation costs.

CUB and CRITFC support Staff's proposal. CRITFC believes that the proposed analysis is important to ensure compliance with HB 3546.

The Coalition supports Staff's proposal, stating that performing a "but for" analysis can help to isolate the resources that are necessary to serve growth. While the Coalition does not believe that a "but-for" analysis alone is sufficient to capture whether an asset is growth-related or not, it is one necessary tool for such a determination. Because PGE's own definition of growth-related is a "but-for" test, in that the company seeks a test evaluating resources that would not be needed at the same time and scope "except for" the need to serve new or incremental load, the Coalition believes that it is reasonable to expect that a "but-for" analysis would be at least one way of determining whether an asset is necessary to serve growth.

PGE argues that a directive to complete a "but-for" analysis in its next CEP/IRP would be outside the scope of this docket. In addition, PGE states that it does not agree that analyses conducted as part of the IRP process should be used to determine rates.

b. Resolution

We decline to require "but-for" analyses in IRP proceedings. We understand Staff's desire for a clearer understanding of investment drivers. However, the PGM approach uses more granular data to allocate known costs to customer classes and situs assigned resources will have relatively clear ties to the loads. Additionally, IRP proceedings are already highly complex with a large number of moving parts and take significant Staff and stakeholder time and resources. For example, we have recently required a counterfactual portfolio to understand the costs of compliance with HB 2021.[34] In

[34] OAR 860-090-0060(12).

updating our rules on resource planning and procurement, we also directed refined approaches to modeling in future IRPs, which may further illuminate the impacts of large load planning in utility IRPs.[35] We do not believe that adding a "but-for" analysis would yield sufficient useful information to be worth further expanding the complexity and resource-intensity of IRP proceedings, particularly given that utilities will, in their next IRP filings, be complying with the new rules recently adopted by this Commission.

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

a. Positions of the Parties

PGE proposes that the PGM be combined with its Energy Growth Modifier (EGM) in the updated net variable power costs (NVPC) to result in a new cost allocation so that growth in the system is proportionally assigned to the customer class that is causing it. Here, PGE requests that the Commission approve a discrete adjustment to how NVPC is 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, PGE states, referred to as the EGM, couples with the PGM to enable growth paying for growth. PGE states that this would allow allocating costs for load growth to each customer class based on their proportionate share of the increase in load from one year to the next.

Staff generally agrees with PGE's proposal, but notes that it was introduced relatively late in this docket. Staff recommends that the Commission require PGE to present a growth-based net power cost rate spread proposal in a subsequent phase of this investigation or a separate proceeding, *i.e.*, PGE's next general rate case or a request by PGE to modify the annual update tariff (AUT)Alternatively, the Commission could adopt PGE's proposal in this docket, with changes implemented in the next AUT. Staff also recommends that the Commission order PGE to present a proposal on how increased power costs due to data center load growth would be spread in the power cost adjustment mechanism (PCAM) in a subsequent phase of the investigation, PGE's next general rate case, or another proceeding.

b. Resolution

We find PGE's proposal for an EGM to be generally reasonable and consistent with the POWER Act's requirement that data center rates mitigate the risk of:

[35] OAR chapter 860, division 90.

> [s]hifting the costs, in an unwarranted manner, of serving a retail electricity consumer that is a large energy use facility to other classes of retail electricity consumers, including costs of an electric company to meet load requirements resulting from the provision of electricity service to a retail electricity consumer that is a large energy use facility.[36]

We also find it to be supported by the record, including PGE's testimony 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."[37] The record shows that this proposal aligns with the principle in this docket that growth pays for growth.[38]

For the 2027 AUT, we approve PGE's request to use a discrete adjustment to how NVPC is calculated in order to include a measurement of increased load growth forecast per customer class. We find that further consideration is required to determine how the EGM should be implemented in future years, and direct that to be addressed no later than in the 2028 AUT. This includes addressing how increased power costs due to data center load growth would be spread in the PCAM. We are concerned that the proposal as drafted may not accurately reflect allocations over multiple years and note that Staff and other parties did not have a chance to fully vet this issue due to it being presented relatively late in this docket.

14. 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?

a. Positions of the Parties

Staff does not support direct assignment of generation assets unless it is through a special contract executed by a customer and the utility. Staff recommends that certain local transmission projects are assigned to large load customers, in whole or in part, to the extent it is determined that load growth from large customers is the major driver in the asset's construction.

Staff proposes that the Commission rely on three sets of data to determine whether direct assignment is appropriate: the "but-for" analysis in the IRP/CEP discussed above; the facilities and cluster studies performed by PGE when a new large load customer connects

[36] HB 3546 § 2(2)(c)(B).
[37] PGE/200, Ferchland-Barrow/16.
[38] PGE/200, Ferchland-Barrow/17.

to the system; and PGE's Long-Term Local Transmission Plan. With respect to the Long-Term Local Transmission Plan, Staff recommends that PGE report load growth by class for the customers served by substations affected by local transmission projects.

Staff believes the assignment should be indefinite but would be subject to change if evidence showed the facility is no longer primarily used to serve large load customers. At this time, Staff does not have criteria that would indicate when a change in the direct assignment of costs may be appropriate.

PGE opposes Staff's proposal, stating that direct assignment of transmission and fixed generation should be rejected because the system is networked and integrated and serves all customers. PGE argues that direct assignment does not reflect the physical reality of how the system operates nor the regulatory principles of cost causation and benefit distribution. PGE states that its generation resources are planned, operated, and dispatched on a system-wide basis and provide shared benefits across all customer classes. It states that its 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.

PGE additionally argues that 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. PGE supports its PGM as an alternative.

AWEC also opposes direct assignment of costs, arguing that it is inequitable and inconsistent with the purpose of those assets. AWEC notes that the Federal Energy Regulatory Commission has a long-standing policy prohibiting direct assignment of networked transmission facilities.[39] AWEC also views directly assigning generation as problematic, stating that generation is not dispatched to meet customer load but instead is dispatched into the market based on prevailing prices. AWEC argues that direct assignment of assets would lead to double charging of costs. It states that data centers would pay both the full cost of transmission assets directly assigned to them and an allocated share of all other transmission assets, even those that only serve small customers. AWEC does, however, support direct assignment when the asset clearly benefits a single customer, such as with radial transmission lines that only supply power to a single customer, so long as the customer is not also allocated costs associated with radial transmission lines that serve other customers. It states that this can occur through PGE's proposed special contracting process.

[39] *Northeast Tex. Elec. Coop.*, 108 FERC ¶ 61,084, 61,433 (July 29, 2004).

DCC states that calls to adopt "direct allocation" of system costs to large customers should be fully vetted in a workshop.

b. Resolution

We find that when a transmission asset is built to serve a single customer, it is appropriate to directly assign the costs of that transmission asset to that customer. The record shows that direct assignment paired with the PGM can fairly allocate transmission costs.[40] We do not believe this will result in double counting, because single-customer facilities across the grid will be directly assigned, leaving only multi-customer facilities to be allocated through the PGM. Therefore, the types of facilities paid for in the PGM will be those that are caused by overall load growth, resulting in just and reasonable rates that avoid unwarranted cost shifts.

15. Should the Commission directly assign the costs of the Shute and Evergreen substations to Schedule 96 or Schedule 90 and 96?

a. Positions of the Parties

CUB recommends direct assignment should apply on a going-forward basis to the revenue requirement associated with the Shute and Evergreen substations that were built as part of the Hillsboro Reliability Project (HRP). Staff agrees, stating that CUB's testimony makes a very good case for the direct assignment and adding that according to CUB's testimony, not a single retail customer is served by the Shute and Evergreen substations. It states that the Commission should order PGE to conduct a study to determine how much growth from either Schedule 90 or Schedule 96 (or a combination of the two) caused these upgrades and direct assign these costs accordingly.

PGE disagrees, stating that for the reasons it opposes direct assignment in general, direct assignment for the Shute or Evergreen substations would not be appropriate. On reply, it states that these facilities serve diverse customer classes beyond data centers and large industrial loads and, importantly, costs are assigned to the HRP, not to specific individual customers. It argues that directly assigning HRP costs to data centers would force the data center customer class to pay for assets they did not necessitate, effectively subsidizing all other customer classes that contributed to the need for those other assets' development.

[40] Staff/300, Stevens/19.

b. Resolution

We do not find that direct assignment of these costs has been justified in this case. However, CUB has demonstrated that additional investigation into the appropriate cost allocation for these projects is warranted. This issue was first raised in 2023 in docket UE 416. Staff there recommended direct assignment to large loads, because that was the primary load that necessitated the HRP.[41] Instead of directly assigning that project, an investigation was opened to look more generally at the issue of cost allocation for large load investments, leading to docket UE 430 and then this proceeding, docket UM 2377. CUB testifies that the Shute and Evergreen substations in particular do not serve a single residential customer.[42] PGE states in its brief that those facilities serve diverse customer classes but does not break down specifically which customer classes they serve. We believe that given CUB's testimony and given the history of this project, additional investigation is warranted. However, this record does not provide the detail necessary to evaluate the appropriate allocation of costs.

Accordingly, we direct PGE to conduct a study to address in detail the customers who caused these upgrades and who are being served by these projects, and then to file that study in its next general rate case for consideration of more specific cost allocation for these projects.

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

a. Positions of the Parties

CUB recommends that data centers be allocated the marginal cost of transmission and other customer classes be assigned the remaining transmission revenue requirement, divided proportionally. The transmission MCOS study identifies the transmission cost for new customers that are adding new load to the system. CUB's proposal would use the MCOS study data to allocate the marginal costs of the system to data centers.

Staff opposes this approach. It believes the combination of traditional cost allocation methodologies, Staff's modified PGM, and the direct assignment of certain local transmission projects will be sufficient in allocating transmission costs to large-load customers. PGE also opposes, stating that transmission costs should be allocated based on the PGM. It views charging the marginal cost of transmission as another method of direct assignment.

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[41] *In the Matter of Portland General Electric Company, Request for a General Rate Revision and 2024 Annual Power Cost Update*, Docket Number UE 416, Order No. 23-386 at 14 (Oct. 30, 2023)
[42] CUB/301, Jenks/1.

b. Resolution

We decline to adopt CUB's recommendation to allocate the marginal cost of transmission to data centers. We find that the combination of the PGM and direct assignment of local facilities will adequately protect all customer classes and avoid unwarranted cost shifts by allocating costs to the customer classes responsible.

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

a. Positions of the Parties

CUB argues that PGE should be directed to study the cost allocation approaches that are outlined by the Regulatory Assistance Project (RAP) in a report submitted by CUB. It states that this study can provide more accuracy to establishing customer classes' contributions to peak growth. Staff agrees.

PGE argues that additional study is not warranted at this time. It states that it found that analyzing the top 100 hours and top five percent of hours with the highest system load in 2024 resulted in higher allocations to residential customers than 4-CP or 12-CP methodologies.[43] Further, it states, any additional study will result in a delay of marginal cost allocation that will benefit customers.

b. Resolution

We agree with CUB that it is worthwhile, at this early stage of implementation of the PGM, to perform analyses of additional approaches and, in particular, those outlined in CUB's testimony that originated in the report by RAP—multiple hours near peak, loss-of-energy expectation, complex base-intermediate-peak, and probability of dispatch.[44] CUB makes the point that smart meters can be utilized for sophisticated measurements, and PGE should consider whether the PGM is better designed with one of those alternatives. We direct PGE to conduct a workshop to discuss these allocation approaches with parties and to provide a report in its next rate case filing comparing the results of the PGM as decided in this case with the estimated results using the suggested alternative analytical approaches.

[43] PGE/400, Ferchland-Barrow-Jose/23.
[44] CUB/300, Jenks/15-16.

D. Rule I - Contract Use and Terms

1. What should the minimum contract term length and minimum contract renewal term length be for large load customer agreements under Rule I?

a. Positions of the Parties

PGE argues for a ten-year minimum term with an automatic three-year renewal. PGE states that by adopting a ten-year minimum initial term plus a 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. PGE argues that a three-year renewal does not run afoul of the POWER Act's requirement of ten-year contracts because the "renewal" is an extension of the original contract, not a new contract.

Staff recommends an LLCA minimum contract term of 10 years that increases with the size of the customer's load. Specifically, Staff proposes 10 years for a 20 MW load, with the term increasing by one year for each 10 MW increment in load and maxing out at 30 years for a load 220 MW or greater. Staff bases its proposal on the greater, in absolute terms, stranded asset risk associated with greater loads. Alternatively, Staff recommends a 15-year minimum contract length for all customers 20 MW and larger. For contract renewals, Staff recommends the minimum term required for data centers, which is 10 years, be applied to all LLCAs.

CUB and the Coalition also recommend minimum contracts of ten years that increase depending on load size. CUB argues that larger data centers between 50 MW and 100 MW should be required to sign 15-year contracts and that data centers that are above 100 MW should be required to sign 25-year contracts. These lengths would also apply to contract renewals of data centers of the stated sizes. The Coalition would scale linearly. Customers with an allocated system capacity of 20 MW would have a minimum contract length of 10 years. The minimum contract length would increase one year with each incremental increase to a customer's allocated system capacity of 5 MW, such that a customer with a capacity of 25 MW would have a minimum contract length of 11 years, 30 MW would be 12 years, and so on. All customers with an allocated system capacity of 120 MW or more would have a minimum contract length of 30 years. The Coalition argues that, when combined with minimum demand provisions and an adequate exit fee, longer minimum contract lengths better protect against overestimated demand, and thus prevent unnecessary additional capital expenditures by PGE and avoids additional stranded asset risk. According to the Coalition, the contract length is the anchor to which

the other anti-overestimation policies are tied. The Coalition notes in addition that if data center customers would balk at a 15- or 20-year minimum contract length, then Staff, the Coalition, and CUB are correct to worry that large customers are likely to leave PGE's territory before they have paid for a substantial portion of the resources built to serve them.

AWEC argues that minimum required contracts should only apply to the new data center class, stating that data centers between 50 MW and 100 MW should be required to sign 15-year contracts and data centers that are above 100 MW should be required to sign 25-year contracts.

b. Resolution

We are persuaded that the proposals to have a minimum contract term of 10 years that increases with the size of the customer are appropriate. The record shows that larger customers create greater risks to the grid and greater risk of stranded assets, and thus greater risk of unwarranted cost shifts to other ratepayers.[45] As the Coalition notes, larger data centers will generally require PGE to expend more capital to facilitate energization than smaller data centers. Loads over 100 MW can impose significant capital expenditures on PGE, totaling over a hundred million dollars just for transmission.[46] And these very large loads—whether data centers or large customers on other rate schedules—come with assets that PGE is likely to be unable to repurpose if the customer goes out of business or relocates; smaller customers, on the other hand, use assets that PGE may well be able to use to serve other customers.

We find that Staff's recommendation to require a term of 10 years for a 20 MW load, with the term increasing by one year for each 10 MW increment in load up to a maximum of 30 years for a load 220 MW or greater is reasonable and consistent with the requirements of the POWER Act. Contract renewals will be for 10 years across the board, which, as the Coalition testifies, will ensure a modest amount of additional cost recovery without overburdening large customers or discouraging renewals.[47] It also prevents a situation where PGE has a large number of very short renewals expiring at the same time, creating uncertainty about what loads will exist on its system at that point.[48]

Finally, we find that PGE's Rule I language regarding contract length—that the term of the LLCA is "measured from the in-service date"[49]—inherently calls for the LLCA to

[45] *See* Staff/300, Stevens/25-26
[46] *See* Staff/300, Stevens/25-26 (extrapolating from a cost of $26 million for a 20 MW load).
[47] Coalition/400, Souder/7.
[48] Coalition/400, Souder/8.
[49] PGE/407, Ferchland-Barrow-Jose/18.

"[s]pecify the date or estimated date that the electric company will begin to provide electricity service to the retail electricity consumer," as required by the POWER Act.[50]

2. Credit requirements

a. Positions of the Parties

PGE proposes to maintain the creditworthiness requirement for large load contracts set in docket UE 430 which states:

> (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.

PGE would also allow additional forms of collateral, which would include, but not be limited to, letters of credit, surety bonds or cash. It is willing to reduce the amount of collateral when a customer stays on the system for a long time, but is not specific about the amount of the reduction or the time period.

PGE argues that it should not have to list its credit requirements in its tariff, stating that including in the tariff the specific detailed aspects for credit worthiness is unnecessarily prescriptive and limiting.

Staff recommends that the requirements be modified so that the credit requirements are specified in tariff rather than in the Customer Service Contract and are uniform. Staff also recommends that PGE:

- Keep its current requirements of senior long-term debt rating of A- (S&P) or A3 (Moody's). If a customer cannot meet these requirements, the applicant would need a letter of credit guarantee from a credit worthy parent.

[50] HB 3546 § 5(1)(b)(A)(iii).

- Allow for surety bonds to be accepted as form of collateral by updating the needed collateral to reflect the value of the customer's Exit Fee.
- Allow for collateral requirements to decrease as the customer stays on the system.

b. Resolution

We agree with Staff that the credit requirements should be specified in the tariff and be uniform. This will provide clarity and avoid potential undue discrimination between customers. The credit requirements will include PGE's current requirements of senior long-term debt rating of A- (S&P) or A3 (Moody's). We agree with both PGE and Staff that surety bonds may be accepted as a form of collateral.

We are not opposed to PGE decreasing the collateral over time; however, the record is silent on how that is to be done. PGE may file to amend the tariff in the future with a more specific proposal.

3. Minimum demand charges

a. Positions of the Parties

(1) Should there be a minimum generation demand charge and what should its terms be?

The POWER Act specifies that any contract entered into with a large data center will "[o]bligate the retail electricity consumer to pay a minimum amount or percentage, as determined by the commission, based on the retail electricity consumer's projected electricity usage for the electricity services the electric company is contracted to provide for the duration of the contract[.]"

Staff recommends setting the minimum generation demand charge (MGD) at 90 percent of the customer's allocated system capacity for all customers 20 MW and larger. Alternatively, Staff recommends a scaled minimum billed demand, ranging from 75 percent for customers between 20 and 70 MW to 97.5 percent for customers above 500 MW. Staff argues that a minimum demand threshold set too low will not be effective at mitigating cost shifts and leaves more stranded asset risk.

PGE recommends an MGD of 80 percent. It states that its approach is in line with peer utilities of which only one—Kentucky Power—has a 90 percent MGD and that only for customers above 150 MW. It argues that setting the MGD too high could violate the

requirement that rates be fair, just, and reasonable, and that it may deter data centers from locating in Oregon. DCC agrees with PGE, stating that no other customer class is subject to minimum demand charges.

CUB recommends PGE apply a charge of 80 percent of generation capacity to data centers that are under 100 MW. Data centers that are above 100 MW should be required to pay 90 percent of the expected generation capacity that they require.

The Coalition agrees with Staff in supporting a 90 percent MGD. It argues that PGE's proposal would incentivize customers to ask for substantially more capacity. It points out that a minimum demand level of 80 percent allows a customer to receive 12.5 percent more capacity while being responsible for the same minimum costs as a customer with a minimum demand level set at 90 percent. According to the Coalition, PGE's data center customers have a load factor of 79 percent, with the result that other customers can benefit from the use of those resources that generally serve data centers only about 20 percent of the time. Because other customers are unlikely to always need those resources when they are available and because the system is already designed to meet the needs of other customers independent of the resources that typically serve data centers, the Coalition believes that 90 percent minimum demand is most appropriate. The Coalition notes that PGE has not explained why a minimum demand greater than 80 percent would be unfairly punitive. The Coalition argues in addition that some of the utilities in jurisdictions cited by PGE reached their minimum demand level through settlement, and that none of those jurisdictions have a legislative directive analogous to the POWER Act.

AWEC argues that any minimum demand charge should be restricted to Schedule 96. It states that if the Commission is going to apply a demand charge more broadly it should apply to all customer classes to avoid discriminatory treatment.

(2) Should there be a minimum transmission demand charge and what should its terms be?

Staff recommends a minimum transmission demand charge (MTD) for Category 3 customers of 90 percent. Staff's secondary recommendation is for the MTD to scale with the customer's size, starting with an MTD of 75 percent for customers between 20 and 70 MW and ending with 97.5 percent for customers over 500 MW. Staff states that large customers have the ability to unilaterally impose significant costs on the system. The assets they require to serve them have 50- to 70-year economic lives and can be of such magnitude that no other industry can fully repurpose these assets in the future. It is therefore reasonable, Staff argues, to establish safeguards to ensure large customers pay

for the majority, if not all, of the cost of the assets that were built to connect them to the system.

The Coalition recommends a 90 percent MTD, for the same reasons it recommends a 90 percent MGD.

CUB also recommends a 90 percent MTD for customers below 100 MW; for customers above 100 MW, it would require a MTD of 95 percent. It states that this will disincentivize customers from requesting more transmission capacity than necessary.

PGE argues for an MTD requirement equivalent to 80 percent of contracted allocated system capacity, which it says maintains the standard adopted in docket UE 430.[51] This percentage, PGE argues, strikes a balance between the need for cost recovery with the fact that transmission is a system resource; it also states that this standard is aligned with the broader regulatory landscape. DCC agrees with PGE, stating an 80 percent MTD incentivizes accurate load forecasting while mitigating stranded-asset risk without imposing punitive obligations on large customers. In response to a data request, PGE stated that it based its proposed MTD on its existing load factor threshold for Schedule 90.[52]

(3) Should there be a minimum distribution demand charge and what should its terms be?

Pursuant to PGE's currently-effective Rule I, "Applicants in Capacity Categories 2B and 3 will be required to sign a Customer Service Contract as a condition of receiving Electricity Service from the Company."[53] Under the heading of "Billed Distribution Demand," Rule I provides:[54]

> If providing service to the Applicant requires the construction of Distribution Facilities, the Customer Service Contract will contain an annual Billed Demand that the Customer must pay at the then-current tariff rates for distribution. Billed Demand will be based on the Company's levelized annual revenue requirement associated with the Cost of Work attributable to the Customer. The annual revenue requirement for Exclusive Use Facilities is allocated 100% to the attributable Customer but is otherwise proportionally assigned. Generally, under any LLCA, the

[51] *See* Portland General Electric Company, P.U.C. Oregon No. E-19, Original Sheet No. I-15.
[52] Coalition/107, Souder/1 (PGE Response to OPUC Data Request 001 (April 10, 2025)).
[53] Portland General Electric Company P.U.C. Oregon No. E-19 Original Sheet No. I-13.
[54] *Id.*

> Billed Demand shall be a flat amount that the Customer will be billed at the then-current tariff rate regardless of the Customer's actual demand.
>
> Billed Demand for a LLCA will be directly calculated as a kW or MW equivalent based on the annual revenue requirement associated with the Cost of Work. Under the LLCA, the Billed Demand will continue during any renewal period if and only if Billed Demand exceeds Allocated System Capacity. If a Customer under a LLCA would be required to pay a Billed Demand amount of less than 25% of its Allocated System Capacity, then the Customer will be billed at the greater of Billed Demand or actual demand.
>
> > Billed Demand for [MLAs] will be set in the fifth year to no less than 75% of Distribution Capacity and set to recover no less than 17% of the Cost of Work totaled over the five-year load ramp period, provided that for each year during the ramp period the Billed Demand many not exceed the Distribution Capacity. Customers under a Minimum Load Agreement will be billed at the greater of Billed Demand or actual demand.

PGE recommends transitioning from flat billed distribution demand to a minimum distribution demand charge (MDD) for LLCA customers equivalent to 80 percent of contracted allocated system capacity. It states this will address concerns about under-recovery of distribution O&M costs and better meet the desire for a simple and standard experience for customers. It also states that it 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.

Staff does not recommend an MDD but instead recommends a flat demand charge for Category 2(b) and (3) customers equal to the total revenue requirement of the customer's dedicated distribution assets. For customers that do not have fully dedicated distribution plant, Staff recommends their flat billing demand be set by calculating their share of the total capacity of the distribution asset multiplied by the revenue requirement of the asset. Staff argues that applying a flat billing demand charge to both Category 2B and Category 3 customers would ensure that no distribution costs for large customers are being spread to other customer classes; and, in addition, that extending this policy to Category 2B customers lessens the incentive for customers to size their capacity allocation request to just below the Category 3 cutoff. Staff also recommends that PGE include a class-wide distribution O&M charge for Schedule 96.

PGE says that if its proposed MDD is rejected, the Commission should maintain a flat billed distribution demand charge. But, it says, 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 customers (because they will see a flat amount, not a variable one that reflects the revenue requirement).

The Coalition argues that PGE makes no attempt to explain why the creation of a data center rate class alters its original argument that, because large customers have dedicated distribution infrastructure, they should pay 100 percent of the cost of that infrastructure. In addition, the Coalition points out that a flat billed demand is more streamlined than minimum billed demand because the customer will be charged the same amount every month for the cost of their incremental distribution resources. Finally, the Coalition claims that the reason that flat-billed demand transitions to actual demand following the initial contract period is because the customer has paid for the full cost of its incremental distribution during the initial term, mitigating the risk of cost shifting even if the customer is charged for actual usage during renewal periods. The Coalition notes that distribution differs from generation and transmission in that it is not a shared asset, at least for customers the size of data centers subject to the POWER Act. Therefore, the Coalition argues, it would be unjust and unreasonable to allow data center customers to pay less than the full cost of those resources and, by extension, shift some of the cost of those exclusive-use assets to other customers.

b. Resolution

The POWER Act requires Schedule 96 customers to execute contracts with minimum demand provisions based on the customer's "projected electricity usage,"[55] but does not specify the level of the minimum demand. For MGD and MTD, the parties have coalesced around either 80 percent or 90 percent for Schedule 96 customers. We adopt a MGD and MTD of 90 percent, finding that they are consistent with the POWER Act's directive to avoid shifting costs from large data centers to other rate classes and will result in just and reasonable rates.

In particular, the POWER Act requires that we ensure that the contract entered into by data centers does not "result in, or have the potential to result in, increased costs or unwarranted risk to other retail electricity customers."[56] As discussed below, the record in this proceeding supports that the 90 percent level is the level at which large load customers are unlikely to shift costs to other retail customers.

[55] HB 3546 § 5(1)(b)(A)(iv).
[56] HB 3546 § 2(3)(a).

Setting the MGD and MTD below 100 percent, where unwarranted shifting would *not* occur, is reflective of the fact that shared resources may provide benefits for other customers. As the Coalition points out, the record shows that PGE's data center customers have a load factor of 79 percent.[57] Accordingly, other customers can benefit from the use of those resources that generally serve data centers only about 20 percent of the time—but, as a practical matter, those resources are unlikely to always be available when other customers need them. Accordingly, a 90 percent MGD and MTD balances the difference between 80 percent and 100 percent, and, as the Coalition states, "acknowledges that customers can benefit from these shared resources but also realizes that those benefits are limited by the high load factor of data center customers."[58]

PGE argues that 80 percent is more in line with industry standards, but we are conscious of our obligations under the POWER Act, which requires us to protect other customer classes without simply relying on industry standards.

While the POWER Act does not govern our review of contracts with large non-data-center customers, we do have a general statutory obligation to ensure just and reasonable rates. We find that protecting against unwarranted cost shifting is necessary to ensure rates are just and reasonable. Thus, we find that a 90 percent MGD and MTD are appropriate for LLCA customers on Schedule 90 as well as Schedule 96. Customers taking service under Schedule 90 must be of a certain size and maintain a load factor of at least 80 percent. We find that this is sufficiently similar to the characteristics of data centers to justify the same MGD and MTD.

There is a dearth of evidence in the record, however, regarding the appropriateness of either increasing Schedule 89 customers' MTD from 80 percent to 90 percent or adding an MGD of any amount for these customers, and accordingly we do not authorize such changes here. We direct PGE to support any proposed changes to minimum demand charges for Schedule 89 customers in its next rate case.

We further find that a flat billed distribution demand is appropriate for Category 2B and 3 customers, as Staff and the Coalition argue. That is reflective of the fact that customers of that size fully utilize distribution assets and they cannot be shared by any other customer. PGE itself stated in docket UE 430 that a "large load customer typically has exclusive use of the distribution voltage assets connected to transmission via a substation transformer."[59] A flat billed charge is more likely to ensure sufficient revenue is collected

[57] Coalition/207, Eiden/1.
[58] Coalition Closing Brief at 17.
[59] Coalition/400, Souder/14, n 20 (citing *In the Matter of Portland General Electric Company, Investigation into New Load Connection Costs*, Docket No. UE 430, PGE/100, Fagan-Frayer/39).

to recover the costs of assets that other customers see little benefit from than a demand charge set to a minimum 80 percent of contracted allocated system capacity. While PGE has since changed its position, it justifies the change stating that an 80 percent MDD would "streamline the customer experience" and "align with existing market standards."[60] As to the first, we understand that taking a different approach to distribution costs as compared to transmission and generation creates complexity for the customer but these are among the most sophisticated energy customers PGE serves. As to the second, the POWER Act requires that we avoid unwarranted cost shifts. Additionally, we find that Staff's approach incorporates class-wide updates to the distribution O&M charges to keep pace with changes to that revenue requirement over time,[61] addressing PGE's contention that this approach risks under-recovery. With respect to non-data-center LLCA customers, which may be served under Schedule 89 or 90, we find that transitioning from the current flat billed demand to an MDD charge of less than 100 percent would create an unacceptable risk of cross-subsidization; that other Commissions have accepted such a risk under particular sets of facts does not persuade us to follow suit here. For the same reasons, we are establishing a flat charge for Schedule 96.

4. Should the large load customer agreement permit PGE to charge a system capacity deposit and what terms should apply to system capacity deposit?

a. Positions of the Parties

PGE argues for maintenance of its current practice, which was approved in docket UE 430. Specifically, it says the Commission should approve a cash deposit due at contract signing equal to two years of minimum transmission demand that is refundable in year two and three post energization subject to the customer meeting 80 percent of their allocated system capacity for distribution, transmission, and generation demands and meeting their contracted flexibility plan. PGE states that it set the length of the payback period to be consistent with the initial three-year term of the system allocation contract.

Staff does not support a system capacity deposit requirement if the customer is subject to an exit fee and make-whole provision if departing early. Staff recognizes that a system allocation deposit guarantees that at least part of the exit fee/make-whole provision will be available upon the customer's early exit. However, Staff is not convinced that the risk of non-payment is sufficient to warrant this additional upfront cost – particularly under PGE's proposal since the payback period is only three years.

[60] PGE/200, Ferchland-Barrow/23–24.
[61] Staff/100 Stevens/54, 60.

The Coalition supports a system capacity allocation deposit, refundable at the end of the contract, because it provides PGE with a monetary commitment from new customers that can hedge against the risk that the customer either goes bankrupt or overestimates its demand. According to the Coalition, requiring an upfront payment provides an altogether different disincentive against overestimated demand than the potential costs of an exit fee. In addition, the deposit is an important component of Rule I to ensure customers adhere to their flexibility requirements. The Coalition states that allowing the deposit to be paid back after three years, as PGE proposes, undermines its ability to influence customers to adhere to their flexibility requirements.

b. Resolution

We approve maintaining PGE's current practice: charging a system capacity allocation deposit due at contract signing equal to two years of minimum transmission demand that is refundable at 50 percent in year two and 50 percent in year three post energization subject to the customer's meeting 80 percent of their allocated system capacity for distribution, transmission, and generation demands and meeting their contracted flexibility plan. We view this as an incentive against over-requesting capacity, which will help avoid potential stranded costs and thus avoid cost shifting to other customers. The record also demonstrates that the system capacity allocation deposit will act as a mechanism to reduce speculative load requests and encourage customers to make realistic assessments of their capacity needs.[62] The deposit also helps to reduce the upfront investment PGE must carry. As the Coalition notes, PGE's proposal would have the deposit refunded by the end of the third year of the contract under most scenarios. Therefore, if the customer exits after the third year of the contract, there will be no double counting with the exit fee, as Staff worries. Accordingly, we adopt PGE's proposal.

5. Should the large load customer agreement and minimum load agreement 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?

a. Positions of the Parties

Staff recommends Rule I specify that PGE is required to charge an exceedance penalty when a customer exceeds its allocated system capacity. Staff also recommends the penalties be specified in tariff. Finally, Staff recommends the penalty provisions include

[62] PGE/100, Ferchland-Barrow/35.

no buffer so that customers are penalized if they exceed their allocated system capacity, rather than only being penalized after some buffer is breached.

PGE proposes a penalty of 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 and would serve as the threshold with no buffer approved. PGE states that this is designed as a strong disincentive against customers exceeding their load. PGE states that 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.

The Coalition and CUB make a similar proposal, though they would include it in the tariff, not in the contract. The Coalition and CUB propose that Schedule 96 customers be charged four times the transmission rate and 1.5 times the generation rate per hour for exceedances of their allocated system capacity, and that the penalty be included in the Schedule 96 tariff, not the customer contract, to facilitate adjustments of the penalty with respect to both existing and new customers if experience demonstrates that the current penalty is either too high or too low.

PGE states that it is open to adding 1.5 times the generation rate to its proposal.

Amazon argues in favor of a 10 percent or 5,000 kW exceedance allowance, as PGE originally proposed. It states that the buffer provides a reasonable allowance for smaller-scale fluctuations in demand and should be retained.

AWEC also argues that the exceedance penalty buffer should not be eliminated, stating that doing so will lead to windfall profits for PGE and no rate relief for customers.

DCC states PGE's current exceedance penalty—set at four times the transmission rate with a 10 percent or 5 MW buffer – is sufficient to deter customers from exceeding reserved capacity. It states there is no evidence that a more severe penalty is necessary to achieve that objective. Proposals to eliminate the buffer or add new exceedance penalties tied to generation investments would therefore be duplicative and overly punitive. It adds that perfect forecasting is not realistic to expect.

b. Resolution

We adopt the Coalition and CUB's exceedance penalty construct, with one modification. In short, the Coalition and CUB propose that Schedule 96 customers be charged, via the

tariff, four times the transmission rate and 1.5 times the generation rate per hour for exceedances of their allocated system capacity. We agree with the Coalition that a generation component of the penalty is important to disincentivize underestimating. Consistent with PGE, Staff, CUB, and the Coalition's proposals, the exceedance penalty will not have a buffer. And we agree with the proposal of CUB and the Coalition that the exceedance penalty be stated in the applicable tariff. However, no party has justified applying the exceedance penalty to Schedule 89 and 90 customers. Accordingly, we direct PGE to include an exceedance penalty provision consistent with these determinations in Schedule 96, and include exceedance penalty provisions consistent with the currently-effective Rule I in Schedules 89 and 90, resulting in no change from the status quo for the latter two customer classes.

In approving this exceedance penalty, we look back at Order No. 24-447, where we stated that underestimated data center loads pose "significant risk of diverting utility resources from other customer priorities."[63] The record shows that underestimation of loads can require the utility to quickly procure additional supply for the underestimating customer, incurring costs that, absent correction, would be spread to all customers.[64] As the Coalition points out, most of the other constructs in this case, including minimum demand, exit fees, and deposits, are designed to prevent overestimated demand; an exceedance penalty, therefore, is a key component of a just and reasonable rate as it discourages underestimated demand. The Coalition also reasonably points out that the penalties against overestimation would actually encourage underestimation without a countering disincentive. Thus, we find both the transmission and generation components of the exceedance penalty to be just and reasonable and find that the penalty provision will provide a limit on cost shifting to other customers, a vital concern under the POWER Act and in ensuring just and reasonable rates more generally.

The question that remains is how the revenues from the exceedance penalties will be treated. We find that it is more appropriate to address the spread of any revenues generated through exceedance penalties as part of a later amortization request when we understand more about the circumstances in which the charges were applied. We order PGE to file an application for a deferral to track revenues from any exceedance penalties.

[63] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 433, Order No. 24-447 at 99 (Dec. 19, 2024).
[64] Coalition/100, Souder/11-12.

6. Early exit fees

a. Positions of the Parties

The current Rule I exit fee imposed upon early termination of a contract includes the following costs related to distribution for customers with MLAs (Category 2B) and those with LLCAs (Category 3): (i) the net book value of the cost of work, and (ii) any additional costs incurred or owing such as decommission costs or net salvage value. The LLCA exit fee includes a third category of costs: 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.

PGE recommends that for customers in an LLCA, the Commission should find that the exit fee should be equal to:

> (1) the net book value of the cost of 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;
>
> (2) 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;
>
> (3) 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.

For customers in an MLA, PGE recommends that the Commission find that the exit fee should be equal to:

> (1) the net book value of the cost of 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,

(2) including any costs of decommissioning and removal of the distribution facilities, net of salvage value as determined by the company in its reasonable discretion, and

(3) costs incurred in connection with the cancellation of third-party contracts.

PGE states that London Economics International found PGE's proposed exit fees to be at the high end in terms of protection for other customers in comparison with other jurisdictions.

PGE, Staff and CUB have each proposed to expand the exit fee charged to customers 20 MW and larger to include costs related to generation and transmission.

PGE terms its proposal a make-whole fee, which it says is in addition to the exit fee. The smallest make-whole penalty a customer might pay for early exiting is three years of minimum transmission demand and generation demand revenue. PGE argues that 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 fee would be eligible for a refund. Category 2B customers would continue to pay the exit fee but would not be responsible for costs under the make-whole provision.

Staff recommends an exit fee for customers with a capacity allocation over 20 MW that is equal to the sum of the minimum demand costs for the remainder of the contract length and the net book value of the incremental distribution assets caused by the customer. For customers with a capacity allocation between 1 and 20 MW, Staff proposes an exit fee equal to the net book value of their distribution assets.

CUB supports an exit fee that would require a data center to pay the generation and transmission demand charges for the remainder of its contract, or five years, whichever is longer.

The Coalition proposes an exit fee that is the sum of (1) the net book value of the incremental distribution assets caused by the customer, and (2) the greater of (a) the remaining MTD and MGD charges for the remainder of the contract, or (b) three years' worth of MTD and MGD charges at the highest allocated system capacity during the contract. It argues that this exit fee effectuates the contract length and minimum demand

terms by holding customers to account for the minimum cost of the full contract even if they leave PGE's system early.

Amazon accepts PGE's exit fee proposal, but notes that it is appropriate within the context of a 10-year minimum contract term, a 3-year contract renewal term, and minimum demand charges for generation and transmission that are no higher than 80 percent. Amazon also states that it accepts the structure of PGE's make whole proposal but asks that the Commission approve PGE's proposal to allow refunds for make whole payments if any portion of generation or transmission can be reattributed to other customers.

AWEC recommends broadly that the exit fee be designed to keep other ratepayers indifferent to an exit, while keeping in mind the reasonableness and burden of the fee on large customers. AWEC states that PGE's exit fee proposal is an appropriate balance.

b. Resolution

We adopt PGE's approach to the exit fee for customers below 20 MW. The proposal is detailed and actionable and will ensure recovery of the distribution system costs that are most difficult to repurpose to another load in a timely manner. However, we find the Coalition's proposed exit fee for transmission and generation costs should be added for loads 20 MW and greater. The record shows that an exit fee like the Coalition's is necessary to protect PGE's other customers from the risk of large scale stranded assets in the event a data center leaves PGE's system before it has paid for the transmission and generation assets PGE invests in to serve the data center.[65] While the parties' various proposals are broadly similar, we find that the Coalition's approach best effectuates the contract length and minimum demand terms when customers leave PGE's system before the end of their contract term. It thus gives effect to the POWER Act's requirement that costs not be shifted unreasonably to other customers and ensures just and reasonable rates by avoiding stranded assets that might otherwise result if large customers (whether data centers or otherwise) exit before the end of their contracts. And as the Coalition witness testifies, "[a]n exit fee worth the value of the expected transmission, generation, and distribution charges for the length of the contract fairly ensures that a data center does not leave other customers footing the bill when it decides to leave PGE's territory."[66]

[65] Coalition/100, Souder/25.
[66] Coalition/100, Souder/26.

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

a. Positions of the Parties

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. Similarly, PGE requests that the Commission allow PGE 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 for the contracted transmission and/or generation within three years. Staff agrees, noting that the refund would be prorated based on the size of the customer and the date the new customer is connected. Amazon also argues that the amounts should be refundable if any portion of generation or transmission can be reattributed to other customers.

b. Resolution

We find that Staff's, PGE's, and Amazon's proposals to allow refunds of the exit fee in whole or in part when another customer assumes the exiting customer's capacity within three years is just and reasonable. We also agree with Staff that the refund should be prorated based on the size of the customer and the date the new customer is connected.

8. How should the funds from exit fees and make-whole provisions be applied?

a. Positions of the Parties

PGE 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 (three years for an LLCA; not applicable for an MLA) would be applied to distribution demand revenue for up to the three-year period from exiting.

Staff recommends applying exit fee revenues to the revenue requirement of the departing customer's customer class to offset the burden of situs allocated costs from the PGM or direct assignment.

b. Resolution

We find that Staff's proposal, to apply exit fee revenues to the revenue requirement of the departing customer's class, is a reasonable approach. The evidence shows that this will ensure the departure minimally affects the customers in their class who remain on the system.[67] As we have stated above, avoiding unwarranted cost shifting for all customers is also an element of ensuring just and reasonable rates. Applying exit fee revenues to the revenue requirement of the departing customer's class will offset the burden of situs allocated costs from the PGM or direct assignment.

9. What should be the kilowatt threshold for the requirement to enter into the large load customer agreement?

a. Positions of the Parties

Pursuant to PGE's existing Rule I, "Applicants in Capacity Categories 2B and 3 will be required to sign a Customer Service Contract as a condition of receiving Electricity Service from the Company."[68] Customer Service Contracts are either an MLA for applicants in Capacity Category 2B or an LLCA for applicants in Capacity Category 3; the terms and conditions for both are outlined in Rule I.[69] Existing customers above 30 MW are thus already subject to an LLCA.

The POWER Act requires that data centers 20 MW and above be required to enter into an LLCA. PGE's position is that customers regardless of schedule will be required to enter into an LLCA at or above 20 MW, stating that this reflects the demarcation line in the POWER Act. Staff agrees. Staff recommends the Commission reduce the threshold for Category 3 customers in Schedules 89 and 90 to 20 MW and that this threshold should apply to Schedule 96 as well. The Stipulating Parties agreed that PGE should "[r]evise Rule I to lower minimum threshold for customers that require an LLCA to 20 MW."[70]

b. Resolution

As stated above, we adopt the proposals of PGE, Staff, and the Stipulating Parties and will revise Rule I—which applies to Schedules 89 and 90 as well as new Schedule 96—to lower the minimum threshold for customers that require an LLCA to 20 MW. This

[67] Staff/300, Stevens/13.
[68] Portland General Electric Company P.U.C. Oregon No. E-19 Original Sheet No. I-13.
[69] Portland General Electric Company First Revision of Sheet No. I-1 P.U.C. Oregon No. E-19 Canceling Original Sheet No. I-1
[70] First Partial Stipulation at 2, paragraph 4.

complies with the POWER Act's requirements as to Schedule 96, promotes consistency across similar rate classes, and upholds the negotiated agreement among the parties.

10. If a customer with a large load customer agreement opts for direct access, will the customer be responsible for minimum generation demand charges, minimum transmission demand charges, and minimum distribution demand charges, and other costs (PGE/400, Ferchland-Barrow-Jose/46-47)?

a. Positions of the Parties

PGE argues that the Commission should find that a customer with an LLCA being served under direct access who is not a prior cost-of-service customer should have the following cost responsibilities related to MGD, MTD, and 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.

PGE argues that a customer with an LLCA that switches from cost-of-service to direct access should have the following cost responsibilities related to 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.

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.

Staff agrees with PGE's proposal.

b. Resolution

While large loads should have the option of direct access, we share PGE's concern that, if it is not structured correctly, large loads' use of that option might result in stranded utility investments or shifting costs or risks onto PGE's remaining customers. Concurrently with this order, we issue an order on direct access that lays out specific charges to be paid as transition charges and other balanced safeguards, such as how the utility will charge direct access customers for energy, should their ESS fail to provide it. Direct access should be an option for large loads that would prefer to procure their own generation from an ESS, but it cannot be an opportunity to avoid paying for costs they have placed on the overall system.

We find that PGE's proposal to avoid such cost shifting is reasonable and consistent with the POWER Act's directive to mitigate the risk of unwarranted cost shifts from large data centers to other customer classes. Direct access loads will pay transition charges, as per our decision in UM 2024; they will also pay the standard system capacity deposit, exit fee, and MDD, as per the tariff. They will pay a 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. We find that this is reasonable balance that will protect cost-of-service customers while allowing direct access as an option.

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

a. Positions of the Parties

PGE argues against the possibility of contract terms being revisited in its next general rate case, stating that its contract terms are durable and should be maintained going forward to promote transparency and consistency in the market and permit market reliance.

Staff is open to revisiting any terms in PGE's next rate case.

AWEC argues that all terms and conditions should be up for review in the next rate case given the myriad novel issues in this proceeding. But it clarifies that it is not supporting revising contract terms for customers who have already signed contracts.

b. Resolution

The Commission retains the discretion to alter terms for new contracts going forward. Those terms may be revisited in PGE's next rate case to the extent parties can make a case that the existing terms have become unjust and unreasonable or that an alternative term would be more just and more reasonable.

E. Cost Responsibilities and Study Terms

1. Should customers who are not required to enter into a minimum load agreement or large load customer agreement 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)

a. Positions of the Parties

PGE believes that customers should be allowed to opt-in to the MLA and LLCA at their discretion if PGE agrees upon review of the application. It states that customers would be opting into more protections, not fewer. Staff does not oppose PGE's proposal.

b. Resolution

We find it reasonable for the tariff to allow customers to opt-in to the MLA and LLCA. As PGE points out, those customers would be opting into additional obligations, rather than attempting to opt out of their own obligations.

2. Should the Commission require PGE to hold unused capacity for customers without a system capacity allocation contract (large load customer agreement or active minimum load agreement)? (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.)

a. Positions of the Parties

PGE states that it 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, PGE says, it should be allocated through contractual terms. Staff agrees.

b. Resolution

We accept the recommendations of Staff and PGE that PGE not be required to hold unused capacity for any customer class or customer outside of contracted capacity allocation, finding that it will mitigate the risk of cost shifting that could occur if the customer for whom capacity were held did not ultimately use that capacity.

3. 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.)

a. Positions of the Parties

PGE believes that substation upgrade costs requirements for interconnection requests that it terms general load growth (1 MW to 3.99 MW) should not be allocated to the customer/applicant. It states that for these smaller customers, it is appropriate for PGE to pay for upgrade costs for the substation.

Staff disagrees, stating that these customers should be treated as Category 2 customers and be required to pay for substation transformer upgrades.

b. Resolution

PGE asserts that substation upgrades to meet interconnection requests between 1,000 kW and less than 3,999 kW should be paid for by PGE—in other words, by all ratepayers—rather than by the customer making the request due to "the general growth aspect of these specific substation upgrades."[71] But it has not explained in what way such upgrades constitute "general growth" as opposed to an upgrade necessitated by a particular customer's interconnection request. Such customers are Category 2 customers under PGE's Rule I and are responsible for substation upgrades associated with their interconnection requests. We find that holding those Category 2 customers responsible for substation upgrades will prevent cost shifting and ensure just and reasonable rates by ensuring that the customers who will benefit from upgrades pay for the costs of the upgrades.

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

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

a. Positions of the Parties

PGE recommends that the Commission approve its request to allocate 100 percent of the costs for any nonpermanent transmission facility upgrades to the customer that is benefiting from that nonpermanent transmission facility upgrade. It states that this cost allocation is appropriate because, since the asset or upgrade itself is nonpermanent, it will be replaced by a permanent asset or upgrade. Staff agrees.

b. Resolution

We find it appropriate to allocate 100 percent of the costs for any nonpermanent transmission facility upgrades to the customer benefiting from the nonpermanent upgrade. The record shows that this aligns payment for facilities with the beneficiaries of facilities and thus prevents cost shifting and ensures just and reasonable rates.[72]

5. Does PGE have any additional clarifications to the language of Rule I that it proposed in this docket? (See PGE/407, Ferchland-Barrow-Jose/2, Rule I redline for the administrative addition of allocation methodology in the definition of Cost of Work.)

a. Positions of the Parties

PGE states that the Commission should approve the new Rule I language clarifying that the cost of exclusive use facilities for an applicant will be allocated 100 percent 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. It states that this language documents the standard practice for the cost allocation of exclusive use facilities. Staff does not oppose this proposal.

b. Resolution

We accept the clarified Rule I language. We find that the standard practice referred to by PGE is reasonable and that it is consistent with the directive in the POWER Act to prevent cost shifting. It is reasonable to codify the practice.

[72] PGE/400, Ferchland-Barrow-Jose/46; *see also* PGE/407, Ferchland-Barrow-Jose/28.

F. Special Contracts

1. Positions of the Parties

As described by PGE, under the special contract option, a customer contracts directly with PGE for dedicated resources, either partial or full, to satisfy some or all of the customer's energy and resource adequacy obligations, bearing the full cost, including energy, capacity, integration, and operational risk, while PGE retains planning visibility and reliability responsibility.

PGE argues that data centers should be able to use Commission-approved special contracts. PGE notes that special contracts are expressly authorized by the POWER Act and states that any special contract would need to be approved by the Commission individually. PGE requests the Commission acknowledge the use of special contracts, which enables timely development of clean, reliable resources that serve new large load data centers without shifting costs or risks to existing ratepayers. It states that these contracts allow PGE to procure generation in parallel with its core portfolio, helping maintain affordability and progress toward HB 2021 goals while ensuring data centers contribute to resource adequacy and decarbonization.

PGE notes that special contracts would be in addition to the existing request for proposals (RFP) process and would not take the place of that process. Instead, 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). 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.

Staff does not oppose the use of special contracts to the extent PGE commits to filing each special contract for Commission approval with information on the resource's cost, performance obligation, and risk allocation. Staff states that the filing should compare the resource with cost-of-service procurements in the RFP; analyze whether the resource meets HB 2021 emissions targets, advances reliability, and meets resource adequacy obligations; and demonstrate that the contract meets the requirements of section 5 of the POWER Act.

The Coalition argues that PGE should be allowed to offer special contracts to its customers as long as the resources customers acquire do not impact the rates that other customers pay. It states that PGE's proposal as drafted would expose its other customers to unwarranted risk of indirect rate increases if data centers are able to acquire all of the least-cost renewable resources in development, leaving only higher-cost options to bid into RFPs to serve PGE's other customers. To prevent that scenario, the Coalition proposes that the resources available for acquisition through special contracts be limited to four categories of non-emitting resources that would not be expected to make a final shortlist in an RFP:

> (1) Resources that have bid into a PGE (or PacifiCorp) RFP and not been included in a final shortlist;
> (2) Co-located resources, built on the same site as a data center;
> (3) Geothermal energy; or
> (4) A catch-all category of Commission-approved resources on a case-by-case basis.

The Coalition specifies that all resources acquired through a special contract should be non-emitting. It argues that limiting the categories of available resources provides regulatory clarity to customers, PGE, and the Commission, ensuring that time and resources are not devoted to the acquisition of generation assets that would not be approved for special contracting upon Commission review.

Staff agrees that resources should be limited to those that do not infringe on resource availability or affordability for cost-of-service customers. Staff also recommends limiting special contracts to resources that do not impede progress towards HB 2021 targets, that advance reliability, and that meet the requirements under HB 3546 Section 5.

PGE says that because the Commission will be reviewing each special contract, it is premature to limit the types of resources that can be used.

PGE states that special contracts should be reviewed and approved by the Commission. Staff states special contracts should be reviewed in a similar manner to resources and agreements submitted under PGE's Voluntary Renewable Energy Tariff (VRET), giving the Commission and Staff time to review the contract prior to a Commission determination at a Public Meeting.

2. Resolution

We will consider special contracts on a case-by-case. The filings should contain, as Staff suggests, a comparison of the resource with cost-of-service procurements in the RFP an analysis of whether the resource meets HB 2021 emissions targets, advances reliability, and meets resource adequacy obligations; and a demonstration that the contract meets the requirements of section 5 of the POWER Act.

We accept the Coalition's proposed list of permissible resources for special contracts. The list is reasonable, and while non-binding, it will nevertheless provide some guidance to parties negotiating special contracts. We find that this is a framework that will allow large loads to bring renewable resources and non-emitting capacity to PGE's system without harming other customers.[73] We find that it will aid in fulfilling the POWER Act's directive that we consider HB 2021 compliance when approving rate schedules under the Act; we also find that it will result in just and reasonable rates both for customers subject to special contracts and for those who are not. Category (4), as an opportunity to explore solutions not included in the first three categories, is particularly crucial as the region grapples with significantly constrained transmission and non-emitting capacity. Large loads may help reduce the risk associated with new resources that will be needed as HB 2021 limits approach zero. They may also bring innovative solutions, such as deep, non-cost effective residential EE to create capacity to serve their loads. The Commission encourages innovative approaches.

We find it reasonable to use a process similar to the one we use in reviewing VRET agreements. Parties should file special contracts with the Commission at least 60 days ahead of a requested decision, though we recognize that contracts raising novel issues or technologies may require more time to evaluate.

G. Contribution in Aid of Construction

1. Positions of the Parties

As noted above, we adopt the Stipulating Parties' agreement that PGE should "[r]evise Rule I to allow any customer with an LLCA or MLA to contribute up to 100 [percent] CIAC for non-shared distribution assets."[74]

Separately, Staff recommends allowing customers above 20 MW to contribute CIAC up to 100 percent of generation and transmission investments. Under Staff's proposal, a

[73] Coalition/400, Souder/39.
[74] First Partial Stipulation at 3, paragraph 8.

customer paying 100 percent of cost of investments needed to serve the customer would allow the customer to skip queues for interconnection (based on transmission or generation need).

PGE opposes CIAC for fixed generation assets or permanent transmission assets. It states those assets provide broad, systemwide reliability and benefits that extend beyond any single customer and therefore are most appropriately funded through regulated cost recovery. PGE also argues that allowing CIAC for fixed generation and permanent transmission assets would require the Commission and parties to determine on a project-by-project basis if an investment is primarily driven by a particular customer; PGE believes that this analysis is inherently speculative in a networked system and inconsistent with long-standing Commission precedent favoring system-based allocation for shared infrastructure. AWEC states its agreement with PGE.

Verrus recommends that flexible customers (in its proposed Schedule 96-F) have avoided costs recognized through a flexibility-deferral credit applied to the growth-related portion of system investments when asset-backed flexibility demonstrably defers or avoids shared or upstream upgrades. Staff opposes this credit.

2. Resolution

As stated above, we adopt the Stipulation's provision that PGE should "[r]evise Rule I to allow any customer with an LLCA or MLA to contribute up to 100 [percent] CIAC for non-shared distribution assets."[75]

As to CIAC for generation and transmission assets, we agree with Staff's recommendation to allow customers 20 MW and above to make CIAC up to 100 percent of generation and transmission investments, potentially speeding the customer's interconnection to the extent that a delay is caused by generation or transmission need. Given the scale of investment in the grid necessitated by forecasted load growth, and the residual stranded asset risk imposed on other ratepayers when PGE funds such investment, PGE and its customers should have the opportunity to rely on customer capital contributions where appropriate. We find doing so will limit the possibility of stranded assets and thus of cost shifting and is therefore consistent with the POWER Act and helps to ensure just and reasonable rates. Allowing customers 20 MW and above to provide CIAC up to 100 percent of generation and transmission investments is also consistent with the POWER Act's directive that we consider whether large data center

[75] *Id.*

rates "[p]rovide for equitable contributions to grid efficiency, reliability and resiliency benefits."[76]

H. Queue for Large Load Customers

1. 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)

a. Positions of the Parties

HB 2021 is an Oregon bill that was passed in 2021 regarding greenhouse gas emissions by Oregon utilities. The bill requires retail electricity providers to reduce greenhouse gas emissions associated with electricity sold to Oregon consumers to 80 percent below baseline emissions levels by 2030, 90 percent below baseline emissions levels by 2035, and 100 percent below baseline emissions levels by 2040. HB 2021 also requires that 10 percent of PGE's aggregate generating capacity come from resources that are smaller than 20 MW.

Staff argues that new large load presents a challenge to PGE's ability to meet these goals as PGE will have to not only build out new non-emitting generation to meet this growth but will have to do so very quickly. To mitigate this impact, Staff recommends implementing a queue for large load customers that would preclude the utility from serving the customer if HB 2021 emission goals would be impeded by serving the customer. Staff also recommends that PGE's special contracts with large load customers be evaluated for compliance with HB 2021 emission goals. Staff argues that this treatment is justified by the size of data center loads and the POWER Act's directive to consider whether rates in PGE's proposed tariff impede PGE's ability to meet clean energy targets set forth in ORS 469A.410 or reduce the emissions of greenhouse gases consistent with state policy.

PGE opposes this proposal. It states that Staff's proposal is summary in nature and "breathtaking both in its impact on customers and its lack of clarity and detail."[77] PGE argues that the proposal is plainly illegal in that PGE has an obligation to serve customers in its service area and an obligation to offer a cost-of-service option. Staff's proposal, it says, violates both obligations. Finally, PGE says that if the Commission were to approve Staff's proposal, it should delay implementation until a detailed plan can be properly developed in a future proceeding.

[76] HB 3546 § 2(3)(b).
[77] PGE Closing Brief at 18.

Amazon also opposes the proposed queue, stating it is discriminatory. It also states that to approve it would be a violation of Oregon law because it could effectively deny service to ratepayers. Finally, it argues that restricting large load on PGE's system may simply shift that load to another system with no emissions benefits for Oregon customers. AWEC also argues that the proposed queue might violate PGE's obligations to serve all customers in its territory.

The Coalition supports Staff's proposal and argues that it would not violate the utility's legal duty to serve because customers would not be barred from receiving service, and in some instances would not even have their service date delayed. It notes that PGE already requires customers to enter a capacity queue over which PGE holds substantial discretion. It notes that the Commission has previously found that in instances where the interconnection lacked capacity to serve the load, PacifiCorp "has the ability to set the timeline and provide the queue position consistent with Commission rules. The rule does not require that the load must be served immediately."[78] Thus, the Coalition states, although a utility cannot simply reject service requests due to shortages on its system, the utility can place a customer in a queue and establish a connection timeline.

b. Resolution

We agree that PGE should establish a queue for service of Schedule 96 customers. Customers in the queue will not be served until a reliable plan of service that matches resources to the load's capacity scale-up plan can be established for the load that does not impede PGE's HB 2021 obligations. To the degree that a load in a higher position does not have a reliable, HB 2021-compliant plan of service in place, a lower queued load may move forward if they are ready with a reliable, HB 2021-compliant plan of service that matches their planned scale-up schedule. The plan of service may include the customer's own non-emitting resources—energy and capacity—in a Commission-approved special contract. It may also include use of direct access, load flexibility. or customer funded load reductions in PGE's service territory. We were assured in our January 21, 2026 hearing by PGE that developing tailored solutions for each customer was preferred and feasible[79] so we remain open to other reliable plans of service.

We make this decision, despite objections from PGE and others, because the POWER Act compels us to consider whether the rates we approve in this order and subsequent orders for Schedule 96 impede the electric company's ability to meet the clean energy targets set forth in HB 2021 or reduce the emissions of greenhouse gases consistent with

[78] Docket No. UE 433, Order No. 24-447 at 114.
[79] Hearing Transcript at 15-18.

state policy.[80] Allowing data center customers to connect to the grid without first ensuring that they are served by HB 2021-compliant sources would be ceding that responsibility. HB 2021 sets out firm emissions caps for PGE in 2030, 2035 and 2040 that do not adjust to account for growing loads. Load growth must be accommodated within those emissions caps and continual progress towards those constrained emissions must be demonstrated in the interim. In reality, all load growth, regardless of source, must be met with non-emitting resources today in order to accomplish HB 2021's mandate.

We do not believe we are precluded from establishing this queue as a matter of law. First, the POWER Act itself is clear that we should consider HB 2021 compliance in the rates we today approve and is silent on the method of implementation; a queue is a just and reasonable alternative to an unordered process of load energization. If load cannot be met without increasing PGE's emissions, then the process of large load energization should pause until a reliable and compliant generation plan is underway. Second, we reject the proposition that a queue constitutes a denial of service, as advanced by several parties. As an initial matter, customers have the ability to move forward through the queue by establishing a plan of service. A higher queued load cannot block lower queued loads. The record shows the customer would be able to utilize load flexibility, special contracts, VRET, direct access service, and onsite generation to avoid waiting for the higher queued project.[81] Moreover, it is by its plain language not denying service to customers, but rather potentially delaying service until that service can be accomplished in accordance with law.[82] This is hardly unprecedented; as the Coalition points out, PGE already requires applicants to enter into a capacity queue over which PGE "reserves the discretion to divide Applicants or Customers into separate queues and to perform studies in clusters."[83] It makes a "good faith effort" to process that queue on a first come-first served basis, but does not guarantee that it will do so.[84]

We discussed the risk of data centers simply choosing to locate in service territories that are not subject to HB 2021's mandates, or for that matter, the POWER Act, at our January hearing. CUB, for example, agreed that there is a risk that data centers could locate elsewhere in Oregon, driving regional costs up for PGE customers without paying PGE anything.[85] Protecting customers as the POWER Act requires, as a result, necessitates a balanced approach to the requirements for large loads that does not incentivize negative arbitrage behavior. In this case, however, while it is possible the

[80] HB 3546 at § 2(3)(c).
[81] *Id.*
[82] Staff/600, Bolton/3.
[83] PGE/407, Ferchland-Barrow-Jose/16.
[84] *Id.*
[85] Hearing Transcript at 68-70.

queue could shift data centers to interconnection with utilities not subject to HB 2021's strictures, that does not obviate our duty to see HB 2021's mandates fulfilled.

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

a. Positions of the Parties

Verrus proposes, as part of its proposed creation of Schedule 96-F for flexible loads, that eligible customers be subject to a "fast-lane" or "fast-track" queue, which it states will accelerate the connection of dispatchable demand response that can absorb off-peak energy and curtail during system peaks.

Staff does not think the record in this case is sufficient to support different treatment for "flexible loads," as is there is insufficient evidence to establish criteria for when load would qualify for the fast track or other particulars. Staff supports exploring this issue in a subsequent phase of this docket.

PGE also opposes. It states that its established practice is to serve load based on available system capacity and this practice already accounts for customer-provided flexibility as a means to accelerate the interconnection of the customer providing flexibility based on the specific system benefit that the customer's flexibility brings. Establishing a formal fast-track interconnection queue, it says, would be unnecessary, and in fact would likely extend the study process for all customers in comparison with the current approach because the study process would have to be bifurcated, creating delay and administrative separation between customers based on whether they bring flexibility.

b. Resolution

We decline to offer a fast-track queue for flexible loads at this time. However, to the extent that special contracts demonstrate flexibility that will help ensure compliance with HB 2021, we will consider those benefits as part of the special contract. Similarly, flexibility may be one element of a plan of service that allows energization.

I. Reporting

1. Positions of the Parties

Staff supports requiring PGE to file an annual report showing the number of customers at or above 20 MW and specifying each (anonymous) customer's facility size, energy demand, water consumption, and associated emissions all broken down by month.

The Coalition argues that the Commission should require PGE to make two sets of reports each year on the usage of its data center customers. First, it says, PGE should make public reports detailing aggregated information about Schedule 96's customer count, customer location, customer type, capacity, total energy usage, peak demand, and water usage. Second, it suggests, PGE should make more detailed, confidential reports that provide anonymized information about individual customer energy usage, water usage, flexibility actions, and additional information that would aid the regulation of these customers.

CRITFC also argues in favor of certain reporting requirements, stating that there should be regular filings from data center customers as to:

- The size of the facility and energy demands;
- The infrastructure required to serve the facility;
- Associated water consumption and effluent expected; and
- Associated onsite emission and emissions from generation resources.

It states that the inclusion of water data is not incidental, but rather directly related to HB 2021 policy protections for environmental justice communities.

PGE states that it has consistently fulfilled its obligation to provide information to the Commission necessary for the Commission's regulation of the utility. Additional information, it argues, is not warranted. PGE cites the reporting requirement set forth in Section 7 of the POWER Act, which requires the Commission to submit a report biennially 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," as a "sufficient reporting requirement."[86]

Verrus opposes the reporting requirements on the grounds of confidentiality, noting that disclosing granular details about a specific facility's energy usage, water consumption,

[86] PGE Opening Brief at 102 (quoting HB 3546 Section 7).

and efficiency metrics would allow competitors to reverse-engineer proprietary operational strategies and production levels and place Oregon data centers at a significant competitive disadvantage as opposed to peers in other jurisdictions.

2. Resolution

Contrary to PGE's contention, the Commission's obligation under the POWER Act to report to the Legislature does not obviate the need for PGE to submit information to the Commission. In order to carry out its own reporting responsibilities, this Commission must collect information from electric utilities subject to the POWER Act. Further, the record shows the importance of transparency, and the manner in which it is key to understanding impacts and allocating costs at both the local level and the grid level.[87] We find reasonable the Coalition's proposal to require PGE to submit aggregated and disaggregated information about Schedule 96 customers, with two amendments: first, the confidential treatment of any part of a filing is a matter to be addressed at the time the filing is made, not in the abstract in this proceeding. And second, while we agree that the water use of data centers is a significant concern, it is a concern subject to the authority of the Oregon Water Resources Department, not this Commission. We thus do not require submission of water usage data.

J. Additional Topics

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

a. Positions of the Parties

CRITFC recommends the utility be required to regularly report and consult with tribal sovereigns whose citizens, rights, and interests may be impacted by the company's provision of service to data center customers. CRITFC notes that PGE already has a tribal relations plan and this is thus readily achievable.

PGE states that it 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 states that it is in the process of launching regional Community Advisory Councils to serve as a planning body to support PGE capital projects and will have a dedicated tribal seat on each of the four councils.

[87] CRITFC/300, DeCoteau/16.

b. Resolution

We do not order PGE here to take specific actions, but we do emphasize how important it is that PGE be in regular consultation with tribal sovereigns. We expect and encourage that it will consult with tribal sovereigns and that the results of that consultation will inform its actions. We expect meaningful engagement on the part of PGE.

2. Should PGE's Tariff be Paused?

a. Positions of the Parties

CRITFC argues that PGE's proposal should be paused until environmental justice communities are shielded from foreseeable costs and risks. In particular, it argues that before implementation, PGE should assess the potential impacts of its proposed tariff and present to the Commission to ensure its tariff creates mechanisms to reduce harm to tribal sovereigns or environmental justice communities.

b. Resolution

We find that it is not necessary to pause implementation of PGE's revised Schedule 96 tariff while additional data is gathered and, in fact, that delaying implementation of the provisions we adopt in this order would actually harm environmental justice communities by failing to put in place the protections we order against cross-subsidization and stranded assets. Pausing implementation of this tariff would leave existing large load tariffs in place, not halt the addition of large loads. Accordingly, we decline to implement CRITFC's proposed moratorium.

3. Minimum Standards for Efficiency

a. Positions of the Parties

CRITFC argues that the Commission should include minimum standards for efficiency, backup storage and flexibility, and energy conservation in the tariff coming out of this proceeding as standard criteria for interconnection. CRITFC argues that these are practical conditions to ensure the tariff shields customers and the grid from expected costs of service.

b. Resolution

We decline to order minimum standards for data centers in this proceeding, finding that we have other mechanisms, including the interconnection queue and minimum demand provisions, of protecting the grid while ensuring that data centers pay their fair share. We find that those provisions are sufficient to be compliant with the POWER Act. We will, as noted above, recognize flexibility, energy conservation, and other grid benefits as a credit in special contracts and consider them on a case-by-case basis. Overall, the tariff has been structured to incentivize minimizing impact on the grid in order to contain costs for all customers.

4. Implementation

a. Positions of the Parties

PGE proposes that the Commission direct PGE to implement changes through a compliance filing as soon as practicable after the conclusion of this docket, and specifically, that the final order require PGE to update rates consistent with the decisions in this docket and the revenue requirement approved in PGE's last general rate case, docket UE 435, and AUT, docket UE 452. PGE believes that there is no reason to delay implementation until the next general rate case or through an alternative mechanism, and states that such a delay would result in any marginal cost principles adopted in this docket to ensure fair allocation of costs not taking effect until a later date, months in the future. PGE states that delaying lower rates for residential and small commercial customers is contrary to the core intent of this docket and unreasonably denies immediate relief to customers. PGE adds that 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. PGE cautions that 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; and it therefore does not advocate for a specific timeframe for implementation other than it should be as soon as practicable after the conclusion of this docket.

Staff recommends implementing the decisions in this docket as a compliance filing to avoid the need for a general rate case as the utilities transition to multi-year rate plans. The Coalition similarly states that this docket should be implemented as a compliance filing to the Commission's final order in this docket. CUB urges the Commission to order PGE to submit a compliance filing reallocating the revenue from the last rate case based on the decisions the Commission makes in this case.

Noting its broader recommendation that this proceeding be limited in scope to Schedule 96, AWEC states that if the Commission does not limit the scope of this proceeding to Schedule 96, any ratemaking treatment changes beyond that required for data centers under HB 3546 should be deferred until PGE's next general rate case to determine proper treatment and further ensure that customers are provided with adequate notice. DCC argues that while PGE should make a compliance filing to implement the Commission's final order in this proceeding, no rate adjustments should be made outside a formal rate case, and PGE should not reallocate the previously-determined revenue requirement with the updated cost-allocation methodology. Amazon agrees that the Commission's decision should be implemented as part of PGE's next general rate case.

b. Resolution

We direct PGE to implement the changes discussed above in a compliance filing at the conclusion of this case. In that compliance filing, we direct PGE to update rates consistent with our determinations in this case and the revenue requirement approved in its last general rate case and AUT. We agree with PGE and Staff that it would not be appropriate to defer the advent of lower rates for residential and small commercial customers to an unknown future date.

We disagree with AWEC's argument that notice requirements were not met. AWEC points to ORS 757.210(1)(a), which requires all public utilities to file with the Commission "any rate or schedule of rates stating or establishing a new rate or schedule of rates or increasing an existing rate or schedule of rates." It also requires the Commission "to determine whether the rate or schedule is fair just and reasonable" and puts the "burden of showing that the rate or schedule of rates to be established or increased or changed is fair, just and reasonable" on the public utility. AWEC argues that PGE did not file a rate schedule showing changes for anything other than the newly created Schedule 96.

However, as PGE points out, notice does not need to be given to all customers who might be affected by a Commission action on a tariff.[88] And AWEC elides that the notice requirement in the statute it cites—ORS 757.210(1)(a)—focuses around hearings: the Commission may, "upon written notice or upon the commission's own initiative, after reasonable notice, conduct a hearing to determine whether the rate schedule is fair, just, and reasonable." The Commission conducted such a hearing and notice was provided in

[88] PGE Closing Brief at 40, n 145 (citing *Low-Income Con. Un.*, 150 Or App at 496, ("[p]lainly, the statute does not require "reasonable notice" unless PUC has decided to hold a hearing [***]. We are not entitled to rewrite the statute[.]," citing ORS 174.010).).

accordance with law and Commission policy and, as PGE references, is still available on the Commission's website.[89] Accordingly, we find that AWEC's notice arguments lack merit.

VI. ORDER

IT IS ORDERED that:

1. Portland General Electric Company must file new tariffs consistent with this order no later than June 3, 2026, to be effective June 10, 2026.

2. Portland General Electric Company is directed to submit an annual report on June 1, consistent with the directives in this order with the first report due June 1, 2027.

3. The First Partial Stipulation attached as Appendix A is adopted.

Made, entered, and effective May 07 2026.

Letha Tawney
Chair

Les Perkins
Commissioner

Karin Power
Commissioner

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

[89] *See* Notice of Prehearing Conference, April 4, 2025, served to UM 2377, UE 430, and Electric Service Lists.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2377

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I.	**FIRST PARTIAL STIPULATION**

This First Partial Stipulation is between Portland General Electric Company (PGE), Staff of the Public Utility Commission of Oregon (Staff), the Alliance of Western Energy Consumers (AWEC), Amazon Data Services, Inc., Climate Solutions, et al. (the Coalition), Data Center Coalition, and Oregon Citizens' Utility Board (CUB), (collectively, the Stipulating Parties).

The Oregon Public Utility Commission (OPUC or Commission) opened this investigation at a Public Meeting on March 7, 2025, resulting in this contested case proceeding, UM 2377. Over the following ten months, Stipulating Parties have participated in three rounds of testimony and answered data requests from Staff, AWEC, CUB, the Coalition, and CRIFTC. At the January 6, 2026 settlement conference, the Stipulating Parties reached a partial agreement that they found reasonable for settlement, which resolves a discrete set of issues within UM 2377. The Stipulating Parties agree the issues outlined in the terms in this First Partial Stipulation are no longer contested and support its adoption. The terms of the First Partial Stipulation are described below.

TERMS OF FIRST PARTIAL STIPULATION

1. **First Partial Stipulation Scope**: This First Partial Stipulation settles a discrete set of issues within docket UM 2377, as set forth herein.

2. **Study Cost:** Adopt PGE's Opening Testimony proposal to charge a flat fee for all studies for customers under 4 MW and allow changes to Rule I, Section 2 outlining the expiration period for study results (60 days unless extended) (PGE Exhibit 407).

3. **Creation of Schedule 96**: Adopt PGE's proposed framework for Schedule 96's rate design that includes: Purpose, Applicable, Monthly Rate, types of charges (basic charge, transmission and related service charge, distribution charges, system usage charge, and generation demand charge), as well as primary and subtransmission service levels.

4. **Large Load Customer Agreement (LLCA) Threshold:** Revise Rule I to lower minimum threshold for customers that require an LLCA to 20 MW.

5. **Load Following Credit:** Do not extend Load Following Credit to Schedule 96 at this time. This resolves all Load Following Credit issues in this docket.

6. **Substation Marginal Cost Study:** Update PGE's distribution marginal cost study t**o** adopt PGE's Opening Testimony proposal to calculate separate substation marginal costs by class to account for the significant differences in the way various customer classes use distribution infrastructure. (PGE/100, Ferchland-Barrow/16).

7. **Queue Maintenance Costs:** PGE will continue to allocate administrative costs associated with queue management under Rule I that are not assigned to an individual customer or applicant only to the rate schedules which utilize the queue.

8. **Contributions in Aid of Construction (CIAC)**: Revise Rule I to allow any customer with an LLCA or MLA to contribute up to 100% CIAC for non-shared distribution assets.

9. **Allocation Claw Back:** Adopt removal of "clawback" as described in PGE/200, Ferchland-Barrow/26 (lines 12-14) and make corresponding changes to Rule I, section 5, to implement its removal.

10. **Site Aggregation:** No changes will be made to the site aggregation definition in Rule I, section 1. This will resolve all issues related to site aggregation for this docket.

11. Unless stated within this First Partial Stipulation, Stipulating Parties may continue to litigate issues associated with Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I, that is currently in contested case proceedings at the OPUC.

12. The Stipulating Parties agree that this First Partial Stipulation is in the public interest and, to the extent applicable to rates, will result in rates that are fair, just, and reasonable and will meet the standard in ORS 756.040.

13. The Stipulating Parties recommend and request that the Commission approve this First Partial Stipulation as an appropriate and reasonable resolution of the outlined issues within this First Partial Stipulation.

14. This First Partial Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this First Partial Stipulation throughout this proceeding and in any appeal, provide witnesses to

support this First Partial Stipulation (if specifically required by the Commission), and recommend that the Commission issue an order adopting the terms contained herein.

15. By entering into this Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation.

16. Except as provided in this Stipulation, no Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

17. The Stipulating Parties agree that without the written consent of all Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, and conduct or statements made at settlement conferences, are confidential and not admissible in this or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

18. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, and conduct or statements made at settlement conferences, are confidential and not admissible in the instant or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

19. The Stipulating Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation, or adds any material

condition to any final order that is not consistent with this Stipulation, each Party reserves its right: (i) to withdraw from the Stipulation, upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation, in whole or material part, or adds such material condition; (ii) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (iii) pursuant to ORS 756.561 and OAR 860-001-0720, to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission order. Nothing in this paragraph provides any Party the right to withdraw from this Stipulation as a result of the Commission's resolution of issues that this Stipulation does not resolve.

20. If this Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission’s adoption of the terms of this Stipulation.

21. The substantive terms of this Stipulation are not enforceable by any Stipulating Party unless and until adopted by the Commission in a final order. Each Stipulating Party avers that it is signing this Stipulation in good faith and that it intends to abide by the terms of this Stipulation unless and until this Stipulation is rejected or adopted only in part by the Commission.

22. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 4th day of February, 2026.

Angelica Espinosa (Feb 4, 2026 10:59:00 PST)

PORTLAND GENERAL ELECTRIC COMPANY

David White

Stephanie S. Andrus (Feb 4, 2026 11:52:43 PST)

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

Claire Valentine-Fossum (Feb 4, 2026 12:30:49 PST)

OREGON CITIZENS' UTILITY BOARD

Tyler Pepple (Feb 4, 2026 11:28:05 PST)

ALLIANCE OF WESTERN ENERGY CONSUMERS

Derek D. Green, o/b/o (Feb 4, 2026 12:45:39 PST)

AMAZON DATA SERVICES

CLIMATE SOLUTIONS COALITION

DATA CENTER COALITION