ORDER NO. 26-309

ENTERED Aug 31, 2026

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2377

In the Matter of	
PUBLIC UTILITY COMMISSION OF OREGON,	ORDER
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.	

DISPOSITION: APPLICATIONS FOR RECONSIDERATION AND REHEARING AND MOTIONS FOR CLARIFICATION GRANTED IN PART AND DENIED IN PART

I. 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 (PGE) 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.

After a full contested case process, the Commission issued Order No. 26-154, establishing a new Schedule 96 specifically for data centers 20 MW and above. We also ordered certain revisions to Schedules 89 and 90, schedules under which other large customers take service. Finally, we ordered revisions to PGE's Rules C and I.

On July 6, 2026, several parties filed for reconsideration, rehearing and/or clarification. Verrus, LLC, filed a motion for clarification and application for reconsideration. The Alliance of Western Energy Consumers (AWEC) filed an application for rehearing, Amazon Data Services filed an application for rehearing and reconsideration, and the Data Center Coalition (DCC) filed an application for rehearing and reconsideration. On July 21, 2026, Climate Solutions, Columbia Riverkeeper, Community Energy Project, Green Energy Institute at Lewis and Clark Law School, Oregon Environmental Council (the Coalition), and the Oregon Citizens' Utility Board (CUB) filed a joint response to the applications for reconsideration and clarification. PGE also filed a response.

II. LEGAL STANDARD

Pursuant to ORS 756.561, any party may file for rehearing or reconsideration within 60 days of an order. Under the Commission's rules, promulgated under that section:

> The Commission may grant an application for rehearing or reconsideration if the applicant shows that there is:
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> > (a) New evidence that is essential to the decision and that was unavailable and not reasonably discoverable before issuance of the order;
> >
> > (b) A change in the law or policy since the date the order was issued relating to an issue essential to the decision;
> >
> > (c) An error of law or fact in the order that is essential to the decision; or
> >
> > (d) Good cause for further examination of an issue essential to the decision.

III. DISCUSSION

A. Interconnection Queue

1. Order No. 26-154

In Order No. 26-154, we found that PGE should establish an interconnection queue for service of Schedule 96 customers. Customers in the queue would 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 House Bill (HB) 2021 obligations. 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.

2. Applications for Reconsideration and Rehearing

a. DCC

DCC, in its application for rehearing and reconsideration, objects to the interconnection queue on several grounds. First, it states that the queue framework errs in moving beyond cost responsibility and into customer access—DCC states that a tariff may establish reasonable service rules, engineering requirements, contribution obligations, and timelines. It cannot, it states, establish a separate queue that withholds service based on whether the company can procure or designate emissions-compliant resources for a customer's load. Next, it argues that the queue conflicts with HB 2021's statutory design, which places emissions-reductions obligations on utilities and other retail providers not on individual tariffed customers. Finally, it argues that the queue is also inconsistent with the record developed after the final order through the Governor's advisory council on data centers. Namely, it states, PGE's presentation to the advisory council identified customer-funded batteries, demand response, and GridCARE capacity as real grid-support tools. Those examples, it argues, support a framework that credits demonstrated customer flexibility and infrastructure contributions, not an open-ended service barrier tied to generalized HB 2021 compliance concerns.

b. Amazon

Amazon, in its application for rehearing and reconsideration, argues that the queue establishes an indeterminate delay or denial of service that is unduly discriminatory and in violation of PGE's statutory obligation to provide its customers with safe and reliable service at reasonable rates and in a non-discriminatory manner. Amazon states that the POWER Act grants the Commission the authority to review rates; however, it states, the interconnection queue is a term of service. Rather, Amazon argues, the law only directs the Commission to "consider" the effects of "the rates" in a tariff on compliance with clean energy targets. Amazon also argues that the order shifts the responsibility to meet HB 2021 obligations from PGE to data center customers as a condition of service.

Next, Amazon argues that direct access is not a viable path due to the waiver criteria adopted by the Commission in Order No. 26-153, issued the same day as the order in this docket. In that order, we stated that we "understand and accept that it is likely not possible for ESSs to demonstrate their participation in a binding regional resource adequacy (RA) program at this time" but that we "believe that it will be possible in the future."[1] Accordingly, Amazon argues, the Commission should reconsider whether there are sufficient methods for a customer to access HB 2021-compliant resources to be energized in a timely manner.

Finally, Amazon argues that FERC's orders to show cause, directed at the six regional grid operators regarding data center interconnections, are in tension with our order. Amazon argues that the Commission should strive to harmonize state and federal law to ensure that the utilities and large data centers experience a cohesive regulatory environment that optimizes the electric grid and generating resources.

c. The Coalition and CUB's Response

The Coalition and CUB filed a response arguing that the interconnection queue should be maintained. First, they argue that there is no legal error, stating that Amazon's argument that the POWER Act only grants the Commission the right to review the *rates* of the tariff is too narrow and would functionally read the requirement to consider HB 2021 out of the statute. They also argue that the queue does not constitute a denial of service and that it does not shift the statute's compliance obligation onto customers.

They also argue that there is no change in law or policy justifying reconsideration. They point out that Order No. 26-153 was issued on the same day—with a lower order number—than Order No. 26-154 and argue that the order makes direct access more available in the long run. They also state that FERC's show cause orders do not warrant reconsideration because they have no impact on PGE. Finally, they argue that there is no new evidence warranting reconsideration as the information that PGE has begun using a ceramic coating on transmission lines to increase capacity on hot days is the only truly new information and it is not "essential to the decision."

d. PGE's Response

PGE filed a response in support of the requests for reconsideration and rehearing. It states that the concerns raised by the Commission in its order would be better addressed in PGE's integrated resource planning proceeding and the Commission's review of special contracts. PGE also argues that the Commission has no legal basis for establishing the interconnection queue due to the obligation to serve. PGE asserts that the POWER Act

[1] *In the Matter of Alliance of Western Energy Consumes, Petition for Investigation Into Long-Term Direct Access Programs*, Docket No. UM 2024, Order No. 26-153 at 24 (May 7, 2026).

only requires the Commission to *consider* HB 2021 compliance, not condition service on it.

3. Resolution

We deny the requests for reconsideration and rehearing. First, we reject the contention that the POWER Act only gives us the ability to regulate "rates" and not "terms of service." The POWER Act states, in relevant part,

> (3) In deciding whether to approve a proposed tariff schedule of an electric company for a classification of service described under subsection (2) of this section, the commission shall consider whether the rates:
>
> (c) Impede the electric company's ability to meet the clean energy targets set forth in ORS 469A.410 or reduce the emissions of greenhouse gases consistent with state policy; ***
>
> (d) Allow for procurement of or contracts for generation resources that support the electric company's ability to meet the clean energy targets set forth in ORS 469A.410 or reduce the emissions of greenhouse gases consistent with state policy; and HB 3546, Section 2(3).[2]

As an initial matter, the distinction DCC makes between "rates" and "terms of service" is an artificial one. Tariffs, by necessity, include both and, in order to ensure that rates are just and reasonable, we must also ensure that service is provided under just and reasonable terms. In this case, as the Coalition and CUB point out in their reply, Amazon's interpretation would have us essentially read the legislature's requirement to consider HB 2021 compliance out of the statute. In order to consider whether data center interconnections will affect HB 2021 compliance, we need to consider something other than solely the amount of money paid by the data center.

Further, ORS 757.295(1)(b)(A)(i) states that any contract entered into by a data center must "be consistent with the criteria listed under ORS 757.292(3)." That includes whether the contract entered into impedes HB 2021 compliance. Amazon and the Coalition and CUB cite to ORS 174.010 to argue that we should give effect to each provision of the statute. We agree with the Coalition and CUB that Amazon's narrow reading of the statute effectively reads HB 2021 compliance out of it.

[2] ORS 757.292; HB 3546 section 2(3) (2025).

Next, we do not agree that the queue constitutes an impermissible denial of service. We addressed this issue in detail in our initial order. We stated: that the POWER Act grants us explicit authority to consider HB 2021 compliance and is silent on the method of implementation; that customers have the ability to move forward through the queue by establishing an alternate plan of service; that a queue merely delays service rather than denying it; and that PGE already requires applicants to enter into a capacity queue.

We disagree with Amazon and DCC's assertion that the queue framework shifts the HB 2021 compliance burden from utilities to customers in contravention of the statute. As the Coalition and CUB point out, the obligation remains on PGE to establish reliable service plans that will connect data centers in its queue *and* to prevent that interconnection from hindering HB 2021 compliance. Further, as noted above, data centers may seek to establish an alternate plan of service, allowing them to bypass the queue.

We find that Amazon and DCC have not established a legal error essential to the decision and thus do not meet our standard for reconsideration on this point.

DCC argues that new material facts have arisen since the order was issued, namely PGE's presentation to the Governor's advisory council on data centers that identified customer-funded batteries, demand response, and GridCARE capacity as real grid-support tools. While we encourage PGE and data centers to use all tools at their disposal, no evidence was submitted that suggests these tools will, by themselves, ensure data centers do not impede HB 2021 compliance. Amazon and DCC have not demonstrated there is new evidence that is essential to our decision and thus, have not met our standard for reconsideration.

Finally, Amazon argues that two changes in law or policy since the issuance of the order warrant reconsideration. First, it states that reconsideration is warranted because direct access is not a viable path under Order No. 26-153, issued on the same day as the order at issue here. As an initial matter, that does not constitute a "change" in law or policy, as it was issued on the same day and in issuing that order, the Commission had full knowledge of the contents of both orders. Indeed, Order No. 26-154 explicitly points to Order No. 26-153 in UM 2024.[3] Moreover, simply because direct access may not be available immediately does not invalidate our order. We have provided other pathways towards service and, in fact, Order No. 26-153 *expanded* direct access by providing a procedure for seeking waiver of the cap, which did not previously exist.

[3] *See* Order No. 26-154 at 54 (May 7, 2026).

Second, Amazon argues that FERC's orders to show cause, issued to the six regional grid operators, are in tension with our order. However, PGE is explicitly not covered by those orders; there is no federal preemption and we see no reason to reconsider our decision as a result. Further, as the Coalition and CUB state, FERC has not yet established any new rules or standards to "harmonize" with; the show cause orders are a request for information from the grid operators. There is no "change of law" to consider and therefore Amazon fails to meet the standard for reconsideration.

Accordingly, we deny the applications for reconsideration and rehearing of our decision to establish an interconnection queue.

B. 30-year Contract Term and Exit Fees

1. Order No. 26-154

In Order No. 26-154, we adopted two sets of provisions that are jointly challenged by the DCC. The first is an exit fee: loads 20 MW and greater exiting PGE's system before the end of their contracts are to pay 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 Minimum Transmission Demand (MTD) and Minimum Generation Demand (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.

Next is the contract term length, which scales with customer size. For a customer that is 20 MW, the minimum contract term length is ten years. The term increases by one year for each 10 MW increment, reaching an upper limit at 30 years for a load 220 MW or greater.

2. Applications for Reconsideration and Rehearing

a. DCC

DCC challenges these provisions and their joint application. It states that requiring a 30-year term with exit-fee exposure creates a substantial risk that Schedule 96 customers will be bound to service terms, load forecasts, and cost-recovery assumptions that may become obsolete long before the end of the contract. DCC argues that the order does not explain why PGE's proposal was insufficient, why a 30-year obligation is necessary for every data center customer above the size threshold, or why generation and transmission investments initially associated with Schedule 96 load could not be repurposed, reassigned, or credited if they later serve other customers or broader system needs. DCC further argues that the order does not address how exit fees will interact with other adopted mechanisms.

As a result, DCC argues, there is an essential error of law or fact and good cause to reconsider the decision. DCC asserts that the Commission should grant reconsideration and clarify that any exit fee must be limited to demonstrable, prudently incurred, unrecovered costs caused by the customer's departure or load reduction; must account for any subsequent use of facilities by other customers or the broader system; must avoid double recovery through rates, minimum demand charges, CIAC, direct assignment, or other tariff mechanisms; and must include reasonable off-ramps where load changes result from circumstances outside the customer's control or from actions that reduce system costs.

b. Verrus

Verrus also seeks reconsideration and clarification of the exit fee. It argues that the exit fee as adopted is inconsistent with the Commission's statutory authority. In particular, Verrus argues that the POWER Act requires that costs be allocated to data centers "in a manner that is equal or proportional to the costs of serving the class"[4] and directly assigned where possible.[5] Verrus also contends that the POWER Act does not relieve the Commission of its long-standing, core obligations under ORS 756.040 and ORS 757.210 to approve only those rates that are fair, just, and reasonable while balancing the interests of customers and shareholders.

Verrus argues that the exit fee adopted by the Commission does not clearly limit the recovery of costs from an exiting customer to the costs incurred, or even a reasonable approximation of the costs incurred, by PGE in serving that customer. Rather, it would require recovery of a minimum amount regardless of whether that minimum amount exceeds stranded costs. It also states that the Commission could, consistent with its authority, adopt an exit fee that includes elements of that proposed by the Coalition, but that this would require additional safeguards to ensure that the amounts recovered in an exit fee do not exceed calculable actual stranded costs incurred by PGE.

[4] ORS 757.292(2)(a)(A).
[5] ORS 757.292(2)(a)(B).

c. The Coalition and CUB's Response

The Coalition and CUB argue that the Commission did not commit a material error of law or fact in approving the exit fee, which was originally proposed in testimony by the Coalition. They state that the exit fee is a function of the rates established in Schedule 96, which will itself be based on the cost-of-service for Schedule 96 customers. They note that the Commission already approved a refund policy for the exit fee in the event that PGE is able to find another customer to take on the capacity of the exiting customer within three years. They also state that the Commission did not misinterpret the facts related to the exit fee; in particular, they contend, it works in conjunction with other provisions to reduce the *risk* of stranded assets by encouraging interconnecting customers to properly identify their capacity needs. They argue that the POWER Act seeks to protect other customers from both cost and risk shifting.

d. PGE's Response

PGE supports the applications for reconsideration and motion for clarification. PGE agrees with Verrus that the exit fee contemplated by the order should be reconsidered because it is excessive, disproportionate, and not supported by the record. However, PGE states that Verrus' recommendation to base the exit fee on PGE's estimate of stranded asset costs with a not-to-exceed cap would be very difficult to administer.

PGE explains that a hypothetical customer with a total system capacity allocation of 220 MW exiting in year one of the required thirty-year term would face an exit fee of approximately $1.5 billion, and even a customer exiting in year ten of the required thirty-year term would still face an exit fee of approximately $1 billion. This, PGE asserts, is greater than what is needed to protect against stranded costs. As an alternative, PGE requests that the Commission require MTD and MGD charges for just three years.

3. Resolution

We grant reconsideration in part. We agree that the exit fee should be adjusted to take into account subsequent use by other customers or the broader system and, in fact, in our decision we stated:

> 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.[6]

We find it appropriate to refund the exit fee in those circumstances, where costs are defrayed by other customers. Additionally, we find it appropriate to adjust the exit fee when it can be determined that, as applied in a specific instance, it is recovering amounts in excess of stranded costs. This will ensure the rates charged to departing customers are just and reasonable while also protecting customers on the system against unwarranted cost shifting. We will not address in this order the precise methodology for making that demonstration. We expect that either the departing customer or PGE would file a petition for Commission decision once the departing customer or PGE expects that the exit fee will recover amounts in excess of stranded costs. We understand PGE's argument that such a showing might be difficult to make, but we find that it is necessary to ensure that the exit fee is tailored to addressing the risk of stranded costs.

C. Direct Access

1. Order No. 26-154

Our order did not address direct access except in that it laid out the cost responsibilities for large load customers who choose to take direct access.

2. Applications for Reconsideration

DCC seeks reconsideration of the combined effect of the order in this case along with Order No. 26-153, issued on the same day, setting new requirements for PGE's (and PacifiCorp's) direct access programs. It states that at minimum, the Commission must clarify how data center customers can use direct access given the companies' current caps for direct access customers. DCC states that Oregon law permits eligible customers to obtain direct access, and the Commission has historically treated direct access as a meaningful supply option rather than a nominal tariff designation.

3. Resolution

The direct access caps to which DCC objects are long-standing. In Order No. 26-153 we maintained the caps at their pre-existing levels, but provided a procedure for waiver of the caps, which we clarified in a subsequent order, Order No. 26-306. That waiver procedure did not previously exist, meaning Order No. 26-153 expanded access to direct access service, making DCC's request inapposite. To the extent that DCC is seeking

[6] Order No. 26-154 at 51.

reconsideration of either the direct access caps or the procedure for waiving the cap, that was properly done in docket UM 2024; it is not properly raised on reconsideration in this docket.

D. 1 cent/kWh Surcharge

1. Order No. 26-154

In Order No. 26-154, we found that a load of 100 MW or more places unique burdens on the system and thus on other customers, such as by utilizing relatively scarce clean energy generation projects or limited transmission capacity, that, while difficult to quantify, are nevertheless real. We accordingly found that applying a surcharge of one cent per kWh to Schedule 96 customers with an Allocated System Capacity of 100 MW or greater to fund non-cost-effective energy efficiency (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. We observed that 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. We observed that the funds collected through the proposed surcharge are not rendered an impermissible additional public purpose charge as a result of being used to benefit the public. We stated that while there is no statutory definition of a public purpose charge, both the structure of the surcharge and the use of the funds distinguish it from the statutory public purpose charge.

2. Application for Rehearing or Reconsideration

a. DCC

DCC requests rehearing or reconsideration. It argues that our conclusion that very large loads cause real but difficult-to-quantify system impacts and that a new charge can mitigate those impacts by funding non-cost-effective EE, enabling repairs, and DERs for energy-burdened customers is not a sufficiently direct cost-causation finding to support a mandatory class-specific surcharge. According to DCC, the more attenuated the use of funds is from the facilities, resources, or services required to serve Schedule 96 customers, the more the surcharge resembles a new public-purpose charge rather than a cost-based rate component.

b. The Coalition and CUB's Response

The Coalition and CUB state that DCC makes no effort to indicate why—in light of the fact that the POWER Act allows the Commission to ensure data centers make equitable contributions to grid efficiency and that data center tariffs and contracts contain provisions the Commission deems necessary to further the public interest—the Commission needed to directly tie the one-cent surcharge to specific costs, facilities, resources, or measurable impacts caused by Schedule 96 customers. The Coalition and CUB argue, the Commission did address the DCC's concern by noting that "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."[7] The Coalition and CUB argue that because it is difficult to identify with specificity those costs and impacts, the surcharge acts as a reasonable stand-in to mitigate the potential cost-shifting effects on low-income customers. They add that the record also shows that the substantial level of new data center load PGE plans to connect in the next five years "will overwhelm the ability of traditional energy efficiency to keep up."[8] The Coalition and CUB believe that the surcharge mitigates this impact equitably by causing those customers driving growth the most—*i.e.*, those over 100 MW—to pay for measures that will reduce the net impact to the grid in a manner that traditional EE measures cannot reach. According to the Coalition and CUB, DCC fails to cite adequate grounds for reconsideration and, to the extent that it raises arguments related to the legality of the Commission's decision, those arguments fail to identify any error in law.

3. Resolution

As we explained in Order No. 26-154, some of the costs data centers impose on the system, such as by utilizing scarce generation and transmission capacity,[9] are quite real despite being difficult to quantify. Such costs are disproportionately borne by lower-income ratepayers, who are frequently energy burdened[10] and are less likely to be able to protect themselves by taking advantage of traditional, cost-effective EE programs which typically require the customer to bear part of the cost of the EE improvements.[11]

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[7] *Id.* at 13.
[8] Coalition and CUB Response to Application for Reconsideration at 20; *see* Coalition/400, Souder/45.
[9] *See* Staff/100 Stevens/47 (noting that transmission is currently "scarce and expensive"); Coalition/100, Souder/41 ("At least in the next five to ten years[,] * * * data centers' seemingly insatiable appetite for new generation could spur an electricity affordability crisis as new electricity demand outpaces new electricity supply"); *see also* Coalition/100, Souder/8 ("[D]ata centers can make the power for surrounding homes worse by distorting the frequency and thereby reducing the power quality. These distortions can reduce the efficiency of appliances and cause wear on their functionality, creating the need for more frequent replacements, the costs of which fall on the owner.").
[10] *See*, *e.g.*, CUB/200, Jenks/16-17.
[11] Coalition/300, Souder/40-42; *see also* Coalition/200, Eiden/39; CRITFC/300, DeCoteau/14-15; CRITFC/400, DeCoteau/4-5; CUB/200, Jenks/17-19.

ORS 757.054 established the existing statutory obligation for electric companies to pursue all cost-effective EE and predates the POWER Act.[12] When implementing the POWER Act, we begin with the presumption that utilities already procure all cost-effective EE to meet new load obligations. The difficult-to-quantify cost pressures on other customers that directly result from the rapid growth of large-scale data centers discussed in the record occur despite the status quo obligation that utilities procure all cost-effective EE.

Extensive evidence provided by multiple parties demonstrates the potential for *non*-cost-effective EE and enabling repairs to at least partially offset the burdens imposed on the grid, and specifically the impact of those costs on low income customers, by large data centers.[13] Funding non-cost-effective EE, enabling repairs, and DERs for low-income customers will directly reduce unwarranted cost-shifting by freeing up scarce non-emitting generation and transmission capacity beyond the status quo and reducing the hard to quantify but very real costs created by scarcity.[14]

It is not clear why DCC believes that the lack of a quantifiable cost-causation finding would cause this surcharge to resemble a new public-purpose charge. While we have found that the condition is in the public interest consistent with the POWER Act, the purpose of this charge is to require very large data centers to at least partially mitigate the risk that other customers are paying unwarranted costs as a result of PGE's data center customers.

Additionally, the POWER Act directs us to consider whether the new data center rates "[m]eet any other conditions the commission may require in the public interest."[15] The legislative directive to "consider" these factors, while less prescriptive than the requirements set out in ORS 757.292(2) and 757.295, is not empty verbiage. These statutory factors are clearly intended to influence our decision-making, including whether additional conditions are in the public interest.

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[12] Our implementation of ORS 757.054 with respect to data centers in light of the POWER Act is addressed in section E below.

[13] Coalition/300, Souder/38-42; Coalition/306, Souder/5-12; CRITFC/300, DeCoteau/14-15; CUB/200, Jenks/17-19.

[14] Coalition/400, Souder/45.

[15] ORS 757.292(3)(e); *see also id*. (2(B))(b) (large data center tariff must "[m]eet the same conditions the commission requires for a contract under ORS 757.295(1)(b)(A)(v)"); ORS 757.295(1)(b)(A)(v) (large data center contract must "[m]eet any other conditions the commission may require in the public interest").

DCC's request for rehearing or reconsideration of the one-cent surcharge is denied.

E. Maximum ORS 757.054 Assessment

1. Order No. 26-154

In Order No. 26-154, we found it reasonable, under either Staff's or the Coalition's interpretation of the evidence regarding the peak demand and capacity factor at which a customer would be likely to organically reach the statutory cap of $4 million per year under HB 3141, to require all Schedule 96 customers to contribute the maximum amount allowable under that cap, including during scale up. We determined that 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[16] by helping to counterbalance the difficult-to-quantify negative externalities that the class imposes on the system. We acknowledged 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, and we agreed 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. Noting that Schedule 96 is a distinct statutory and tariff classification, created under the POWER Act, however, we found that 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 found that the approach adopted in Order No. 26-154 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.

2. Application for Rehearing or Reconsideration

a. DCC

DCC requests rehearing or reconsideration, arguing that HB 3141 or another statute establishes a cap, we must explain why the Commission may convert that cap into a mandatory charge for Schedule 96 customers before the cap is otherwise reached. DCC states that we also must reconcile that treatment with the evidence that customers may not reach the cap during scale up and with arguments that data centers would be treated differently from other large industrial customers without an adequate statutory or factual basis. It argues that Order No. 26-154 lacks substantial evidence of a cost caused by Schedule 96 service on this issue, as well as a clear statutory basis to convert an annual

[16] ORS 757.292(3)(b).

cap into a mandatory floor. DCC observes that ORS 757.612 establishes a non-bypassable public purpose charge equal to 1.5 percent of covered retail electricity revenues, subject to large-user caps. DCC requests that the Commission rescind the surcharge and mandatory maximum contribution requirement, defer those issues to a rate case or separate tariff proceeding with a developed evidentiary record, or narrow them to costs directly caused by Schedule 96 service.

b. The Coalition and CUB's Response

The Coalition and CUB note that the POWER Act requires the Commission to review whether a large data center's tariff and contract "provide for equitable contributions to grid efficiency."[17] They state that the POWER Act also grants the Commission the authority to include in either a large data center tariff or contract "any other conditions the commission may require in the public interest." The Coalition and CUB argue that ORS 757.054 does not specify that all customers must contribute equally or proportionally towards cost-effective EE; it only states that the funds collected "to plan for and pursue cost-effective energy efficiency resources * * * must be collected in the rates of an electric company through charges paid by all retail electricity consumers." When paired with the POWER Act's call for "equitable contributions" to grid efficiency, the Coalition and CUB state that the Commission had ample authority to require Schedule 96 customers to pay the full amount allowable under the HB 3141 cap by increasing their contributions towards ORS 757.054-related cost-effective EE. In addition, the Coalition and CUB note that in testimony, CUB showed that residential customers have been paying an increasing share of the budget of the Energy Trust of Oregon in recent years without a corresponding increase in the proportionate efficiency savings.

3. Resolution

DCC's application does not meet our standards for rehearing or reconsideration on this issue; it has not demonstrated an error or law or fact essential to the decision or shown good cause for us to reexamine the issue.

The POWER Act requires us to consider whether any large data center tariff "provide[s] for equitable contributions to grid efficiency, reliability and resiliency benefits"[18] and "[m]eet[s] any other conditions the commission may require in the public interest."[19] DCC is correct that ORS 757.612 establishes a public purpose charge of 1.5 percent of

[17] ORS 757.292(3)(b).
[18] *Id*.
[19] ORS 757.292(3)(e).

covered retail electricity revenues; Order No. 26-154 does not alter that statutory approach. ORS 757.054 establishes an additional charge:

> "All funds necessary to plan for and pursue cost-effective energy efficiency resources pursuant to subsection (3)(a) of this section must be collected in the rates of an electric company through charges paid by all retail electricity consumers, including those retail electricity consumers receiving electricity from electricity service suppliers subject to the limitations set forth in section 3, chapter 547, Oregon Laws 2021."[20]

The HB 3141 $4 million cap applies to "the combined annual amount charged under ORS 757.054 and 757.612."[21] The additional charge is thus under ORS 757.054, not ORS 757.612.

We determined, based on the evidence in the record before us,[22] that requiring all Schedule 96 customers to contribute the maximum amount allowable under HB 3141 is a reasonable condition in the public interest and provides for equitable contributions to grid efficiency, reliability, and resiliency benefits. As we recognized in Order No. 26-154, our ability to direct such contributions in proportion to customers' energy use is constrained by the statutory limitation of $4 million per year. Instead, we have determined that all Schedule 96 customers should be treated the same in this respect. We acknowledge that this approach differs from that used for other large industrial customers, but note that this different treatment is a product of the additional statutory requirements placed on the data center rate class and our additional public-interest conditioning authority under the POWER Act.

DCC's application for rehearing or reconsideration is denied.

F. 90 Percent Minimum Generation Demand and Minimum Transmission Demand

1. Order No. 26-154

In Order No. 26-154, we adopted MGD and MTD charges 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. Citing the POWER Act's requirement that we consider whether large data center rates "result in, or

[20] ORS 757.054(4).
[21] Oregon Laws 2021, chapter 547, section 3(4)(a).
[22] *See*, *e.g.*, Coalition/300, Souder/37-42.

have the potential to result in, increased costs or unwarranted risk to other retail electricity customers,"[23] we found that the record in this proceeding supports that the 90 percent level appropriately mitigates the risk that large load customers are shifting costs to other retail customers. Specifically, we reasoned that setting the MGD and MTD charges below 100 percent, where unwarranted shifting would not occur, is reflective of the fact that shared resources may provide benefits for other customers. The record shows that PGE's data center customers have a load factor of 79 percent.[24] This means that other customers could benefit from the use of those resources that generally serve data centers at most about 20 percent of the time – though only to the degree those resources are needed by other classes. As a practical matter, those excess resources are unlikely to always be available when other customers need them. Accordingly, 90 percent MGD and MTD charges balance the difference between 80 percent and 100 percent, acknowledging that customers can benefit from these shared resources but also recognizing that those benefits are limited by the high load factor of data center customers.

2. *Application for Rehearing or Reconsideration*

a. DCC

DCC argues that Order No. 26-154 does not sufficiently explain why 90 percent rather than 80 percent is necessary for all covered customers, regardless of individual ramp characteristics, energization timing, facility sharing, or operating profile. According to DCC, Order No. 26-154 never explains why PGE's proposed 80 percent minimum demand charges fail to mitigate cost shifting. DCC states that this omission is material because the Commission did not quantify the incremental revenues that Schedule 96 customers would provide under PGE's 80 percent proposal, or the incremental revenues produced by moving from 80 percent to 90 percent. DCC argues that a cost-shift analysis that considers only potential incremental costs, and not incremental revenues, fixed-cost spreading, customer-funded grid resources, or other offsetting system benefits, is not a cost-causation analysis; it is a risk-only analysis. In its application for reconsideration, DCC provides a figure that it terms an "illustrative example," with a request that PGE verify its calculations.[25] DCC requests rehearing or reconsideration and asks the Commission to reduce the minimum demand requirement to PGE's proposed 80 percent unless PGE demonstrates customer-specific need for a higher minimum.

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[23] ORS 757.292(3)(a); *see also* ORS 757.292(2)(c)(B) (large data center tariff must "[m]itigate the risk of * * * [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").
[24] Coalition/207, Eiden/1.
[25] DCC Application for Rehearing or Reconsideration at 26.

b. The Coalition and CUB

The Coalition and CUB state that DCC does not specifically identify the basis under OAR 860-001-0720(3) upon which it seeks reconsideration. According to the Coalition and CUB, that failure alone provides reason for the Commission to deny reconsideration. The Coalition and CUB suggest that by process of elimination it seems that the DCC is claiming that reconsideration is warranted due to an error of fact essential to the decision, given that it does not raise new evidence, does not identify a change in law or policy, does not cite to any legal infirmities, or reference "good cause." They argue that reconsideration is not warranted because the Commission's decision was rooted in substantial evidence. The Coalition and CUB point out that the POWER Act requires a minimum demand charge but leaves to Commission discretion the level at which to set it, so long as it conforms to the other provisions preventing cost- and risk-shifting.[26] They state that theoretically, only a minimum demand of 100 percent would not "result in, or have the potential to result in, increased cost or unwarranted risk" to other customers.[27] The Coalition and CUB reiterate the evidence supporting the determination in Order No. 26-154 that a minimum demand of 90 percent provided adequate acknowledgement of the fact that generation and transmission are shared, but in practice a data center's portion of those resources are very rarely available to other customers.

The Coalition and CUB state that while DCC argues that the Commission's analysis should have considered "incremental revenues, fixed-cost spreading, customer-funded grid resources, or other offsetting system benefits,"[28] neither DCC nor any other party provided that evidence to the Commission, nor did they do the more important task of showing how those factors would warrant a lower minimum demand charge.

3. Resolution

As discussed above, we explained in Order No. 26-154 the rationale for, and record evidence underlying, our policy choice of 90 percent minimum demand charges rather than 80 percent, including our explanation that setting the demand charges at 80 percent—close to Schedule 96's load factor of 79 percent—would fail to account for the fact that as a practical matter, the resources built for data center customers are unlikely to always be available at the times that other customers need them – to the degree other customers need them at all.[29]

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[26] ORS 757.295(1)(b)(A)(iv).
[27] Coalition and CUB Response to Applications for Rehearing or Reconsideration at 21, n 75 (quoting ORS 757.292(3)(a)).
[28] *Id.* n 76 (quoting DCC Application at 26).
[29] Order No. 26-154 at 42-43.

We understand DCC's reference to "individual ramp characteristics, energization timing, facility sharing, or operating profile" as an argument that, for example, an individual data center may have a load factor either higher or lower than the class's average of 79 percent. Variation within a class, however, does not undermine the widespread and longstanding practice of setting uniform rates by customer class.

It is not clear what impact DCC believes consideration of incremental revenues would have on our determination, nor does it cite an evidentiary basis in the record for us to do so. The figures included in DCC's application for reconsideration[30] are not "[n]ew evidence * * * that was unavailable and not reasonably discoverable before issuance of the order"; they are unverified illustrations of existing information. The parties to this case had the opportunity to present evidence if a 90 percent MGD or MTD charge risked unwarranted, class-wide over-recovery of revenue for assets built to serve the class. Parties may raise and litigate issues including incremental revenues, fixed-cost spreading, customer-funded grid resources, and other offsetting system benefits in future rate cases where relevant.

DCC's application for rehearing or reconsideration of the 90 percent MGD and MTD charges does not meet any of the standards for reconsideration; the application is denied.

G. Minimum Billed Distribution Demand

1. Order No. 26-154

In Order No. 26-154, we found that a flat billed distribution demand is appropriate for Category 2B and 3 customers, noting the fact that customers of that size fully utilize distribution assets and they cannot be shared by any other customer. We found that a flat billed charge is more likely to ensure sufficient revenue is collected 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. Additionally, we found that the approach adopted incorporates class-wide updates to the distribution O&M charges to keep pace with changes to that revenue requirement over time, addressing PGE's contention that this approach risks under-recovery.

[30] DCC Application for Rehearing or Reconsideration at 16, 26.

2. Application for Rehearing or Reconsideration

a. DCC

DCC argues that Order No. 26-154 does not sufficiently explain how a flat distribution charge avoids over-recovery when facilities are shared, later become useful to others, or are not exclusively dedicated to one customer. It requests rehearing or reconsideration and asks us to require reconciliation, credits, or reassignment where distribution facilities are shared or later used to serve others.

b. Response

The Coalition and CUB note that the flat billed distribution scheme only applies for incremental distribution built for a large data center, and that evidence in the record showed that large data centers generally utilize non-shared distribution facilities. The Coalition and CUB argue that a flat billed scheme is not only warranted, but likely required, given the non-shared nature of those resources and the POWER Act's requirement to avoid unwarranted cost-shifting.

3. Resolution

Order No. 26-154 adopted a flat-billed distribution demand framework for Category 2B and 3 customers, with class-wide updates to the distribution O&M charges to keep pace with changes to that revenue requirement over time. That the order leaves some implementation details to be resolved as they arise in rate case proceedings does not constitute an error of fact or law essential to our decision, nor has DCC shown good cause for us to reexamine this issue. Its application for rehearing or reconsideration is therefore denied. We clarify, however, that for any customers that have shared distribution plant, each customer's flat billing demand should be set by calculating its share of the total capacity of the distribution asset multiplied by the revenue requirement of the asset.[31]

H. Exceedance Penalty

1. Order No. 26-154

In Order No. 26-154, we adopted the exceedance penalty as proposed by the Coalition and CUB, with respect to Schedule 96 only. Under the approach adopted, customers are

[31] *See* Staff/300, Stevens/29.

charged four times the transmission rate and 1.5 times the generation rate per hour for exceedances of their allocated system capacity; there is no buffer.

We based our decision on evidence 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.[32] And we recognized that most of the other rate design elements 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. We thus found both the transmission and generation components of the exceedance penalty to be just and reasonable and found that the penalty provision will provide a limit on cost shifting to other customers.

We found it 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 therefore ordered PGE to file an application for a deferral to track revenues from any exceedance penalties.

2. *Application for Rehearing or Reconsideration*

a. DCC

DCC requests rehearing or reconsideration. It argues the exceedance penalty appears designed in part as an incentive or deterrent, stating that while that may be a policy objective, the specific multipliers and no-buffer design require record support tying them to costs, reliability risk, or a proportional administrative need. DCC also asserts that the deferral to track revenues from any exceedance penalties confirms the cost basis and customer benefit of the penalty were not fully resolved when the penalty was adopted. DCC requests that we adopt a reasonable exceedance buffer or a cost-based cap.

b. The Coalition and CUB's Response

The Coalition and CUB note that the POWER Act specifically grants the Commission authority to require an exceedance penalty.[33] They cite record evidence demonstrating the need for an exceedance penalty to recover potential costs associated with demand exceedances, to disincentivize underestimated demand, and, relatedly, to balance against policies that disincentivize overestimated demand.[34] They point in addition to evidence

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[32] Coalition/100, Souder/11-12.
[33] Coalition and CUB Response to Applications for Rehearing or Reconsideration at 23, n 79 (citing ORS 757.295(2)).
[34] *Id.*, n 80 (citing Coalition/100, Souder/11-12; CUB/200, Jenks/40; Staff/300, Stevens/45).

submitted by the Coalition showing that its recommended exceedance penalty level was necessary to properly disincentivize underestimated demand because a lower penalty would allow customers to exceed their allocated system capacity for many hours before suffering a true "penalty."[35]

3. Resolution

The transmission rate and generation rate paid by a Schedule 96 customer are set tariffed rates; they are not direct pass-throughs of PGE's hour-by-hour costs of transmission and generation. A utility's costs to quickly procure additional supply for a customer exceeding its allocated system capacity are difficult to predict with precision, or even to unwind from the utility's overall operating costs after an exceedance has occurred. We found, based on the record before us, that an exceedance penalty is needed to deter underestimation of demand. Several aspects of the tariff, including the minimum demand, exit fees, and deposits, all incentivize a data center customer to under-estimate their demand to limit ongoing costs. It would be economically rational, in light of the tariff design, to assume any exceedance buffer into the site design and use it regularly to avoid the otherwise predictable costs of the tariff. Essentially, a ten percent buffer has the same effect as resetting the MGD and MTD charges to 80 percent rather than 90 percent. Under the POWER Act, data center customers are required to bear the cost of their actual demand, including estimating their risk of exceeding their typical usage. The penalty adopted will provide an appropriate deterrent, balance the incentives to over- versus under-estimate load, and limit cost-shifting to other customers. These findings are not undermined by the infeasibility of tying the penalty more directly to the costs associated with a particular exceedance event.

DCC also provides no evidence for its request that we adopt an exceedance buffer. We note, however, that the inappropriateness of a buffer is supported by record evidence pointing out that even a relatively small buffer of 5 MW (which is equivalent to 10 percent of the load of a 50 MW data center) is the equivalent of adding 4,700 residential customers to PGE's system; the scale of large data center loads is such that even small exceedances can have substantial system-wide effects.[36] Socializing the cost of a buffer of that magnitude would inappropriately shift risk from the data center rate class to PGE's other customers.

DCC's application for rehearing or reconsideration is therefore denied.

[35] *Id.*, n 81 (citing Coalition/400, Souder/9–10; Coalition/402).
[36] Coalition/100, Souder/28.

I. Peak Growth Modifier

1. Order No. 26-154

In Order No. 26-154, we found that the Peak Growth Modifier (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. We found that the PGM will support more sustainable and equitable rate structures across all customer classes. We adopted proposals by several parties to make allocations to the PGM indefinite, rather than from three to ten years, as proposed by PGE; in other words, a growth-related asset will remain in the PGM until it is demonstrated that system usage no longer supports the allocation. We found that this approach will most fairly allocate growth-related investments among the customer classes, aligning with the POWER Act's directive that utilities protect against cross-subsidization of large data centers. We also found 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.

To better align with the sequencing of procurement to serve anticipated load growth, prevent cross-subsidization, and avoid a mismatch between the timing of customers coming online and when capital is placed into service, we adopted Staff's proposal that the test year load forecast be incorporated into the PGM.

We adopted PGE's framework, as modified by Staff, for determining whether investments are load growth-related: 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 characterized this approach as "a reasonable starting point,"[37] and acknowledged the possibility that it might ultimately spark an inefficient amount of litigation in rate cases when PGE brings these assets into service. We stated that we will continue to evaluate the method adopted in Order No. 26-154 as it is applied in future proceedings and will consider changes should a party bring forward more objective criteria at that time.

[37] Order No. 26-154 at 23.

2. Application for Rehearing or Reconsideration

a. DCC

DCC requests rehearing or reconsideration the portions of Order No. 26-154 adopting the PGM, defining growth-related transmission and generation assets, using test-year forecasts, and treating growth-related allocations as indefinite unless later evidence shows the asset no longer supports growth. DCC argues that Order No. 26-154 does not sufficiently constrain how assets are classified as growth-related, how long growth-related treatment continues, or how forecasted load is reconciled if projected load does not materialize. It states that the record reflects several distinct causation concepts: "but-for" causation, primary driver, direct assignment to a single customer, and general growth contribution. DCC requests that we modify Order No. 26-154 to require objective asset-classification findings, a periodic review or sunset for growth-related treatment, reconciliation when forecasted load fails to materialize, and express safeguards against locking in allocation results based on stale forecasts.

b. PGE Response

In response, PGE notes that the Commission did not permanently lock growth assets into the PGM regardless of changing circumstances. Rather, under the adopted framework, assets will no longer be treated as growth-related when system usage no longer supports that allocation.

c. The Coalition and CUB's Response

The Coalition and CUB state that DCC seems to argue that, because the record contains arguments for many concepts of "growth-related," the Commission erred. The Coalition and CUB note that in Order No. 26-154, the Commission adopted PGE's definition of growth-related with modifications from Staff, and argue that this decision does not constitute error.

3. Resolution

Order No. 26-154 adopts guidelines for classifying assets as growth-related and determining how long growth-related treatment continues. We expect these guidelines to be applied—and litigated—in rate cases. As we stated in Order No. 26-154, the record in this proceeding is not sufficient to develop the more objective criteria under Staff's proposal, but we remain open to changing the guidelines adopted in Order No. 26-154 based on the implementation experience gained in future rate case proceedings.

In Oregon's approach to ratemaking, there is always a risk to both the utility and ratepayers that the test year forecast will prove to be inaccurate. We note, moreover, that if significant new load is expected in the test year, it is very likely that PGE has already begun to make procurement commitments to serve that load. This is why we directed that the test year load forecast be incorporated in the PGM. The risk that significant test year load fails to materialize is a stranded-asset risk addressed by numerous directives in Order No. 26-154.

DCC's application for rehearing or reconsideration does not show an error of fact or law essential to our decision with respect to the PGM, nor does it show good cause for us to reexamine this issue. Its application is denied.

J. Direct Assignment

1. Order No. 26-154

In Order No. 26-154, we determined 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. We found based on the record that direct assignment paired with the PGM can fairly allocate transmission costs.[38] We stated that we do not believe that this approach 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.

2. Application for Rehearing or Reconsideration

DCC requests that we clarify the boundary between single-customer facilities and network facilities. DCC argues that direct assignment may be appropriate for dedicated, single-customer facilities, but transmission facilities can be networked and can provide systemwide benefits. DCC requests that we clarify that direct assignment applies only to facilities demonstrably built solely for one customer, excludes facilities with material network benefits, and must include safeguards against double counting. DCC is concerned that without the requested clarification, implementation may assign costs directly to a customer even when facilities provide broader system benefits or when the same facilities are also reflected in growth modifiers, base rates, or future allocation mechanisms.

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[38] Staff/300, Stevens/19; *see also* Staff/500, Stevens/24.

3. Resolution

It is clear that Order No. 26-154 does not contemplate the direct assignment of networked transmission facilities. Determinations as to whether particular assets should be (or should continue to be) directly assigned will be fact-specific and are properly resolved in the context of a rate case, as are determinations as to whether directly-assigned assets are also improperly reflected in other cost allocation methods. DCC's request for rehearing or reconsideration is denied.

K. Reporting Requirements

1. Order No. 26-154

In Order No. 26-154, we noted that in order to carry out our own reporting responsibilities under the POWER Act, this Commission must collect information from electric utilities that are subject to the POWER Act. Evidence presented in this proceeding demonstrated the importance of transparency, and the manner in which such transparency is key to understanding impacts and allocating costs at both the local level and the grid level.[39] We adopted the Coalition's proposal to require PGE to submit aggregated and disaggregated information about Schedule 96 customers, with two amendments: first, that 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, that we did not require submission of water usage data, which is outside our purview.

2. Application for Rehearing or Reconsideration

a. DCC

DCC requests rehearing or reconsideration. DCC requests that the Commission clarify that customer-specific Schedule 96 information may be submitted confidentially and protected from public disclosure, including load forecasts, ramp schedules, facility-development information, tenant or end-use information, energy-procurement strategy, direct-access plans, interconnection timing, and contract-specific cost information. DCC argues that the Commission should further clarify that public reporting should use aggregated, anonymized, or redacted information wherever possible, and that any customer-specific disclosure must be limited to information necessary for Commission review. DCC expresses concern that without clear confidentiality rules, implementation of mechanisms such as the separate queue, service agreements, ramp schedules, minimum demand obligations, direct assignment, exit fees, direct-access

[39] CRITFC/300, DeCoteau/16.

variations, and growth-related allocation treatment could require repeated public disclosure of customer-specific information that should be protected.

b. The Coalition and CUB's Response

The Coalition and CUB argue that much of what DCC asks the Commission to now specify as confidential, including "ramp schedules, facility-development information, tenant or end-use information, energy-procurement strategy, direct-access plans, interconnection timing, and contract-specific cost information" would not be included in the annual report the Coalition requested and the Commission approved.[40] They state that DCC makes no specific argument related to the information actually approved for reporting, does not explain why or how reports on data center energy use would divulge commercially sensitive information, and does not show why the Commission's decision to deal with confidentiality at the time a report is made would not adequately address DCC's concerns.

c. *PGE Response*

PGE states that it takes no position on DCC's reconsideration request on this matter. PGE agrees with the concerns expressed by DCC about the treatment of confidential customer information and states that the security and protection of customer usage and other confidential information is important to PGE.

3. Resolution

This Commission is subject to Oregon's Public Records Law, ORS 192.311 through 192.478. The Commission's rules on protective orders[41] and confidential information[42] govern our handling of information within the scope of ORCP 36(C)(1). We cannot make categorical determinations in the abstract that certain filings will always be exempt from public disclosure; such determinations are necessarily fact-specific. DCC's request for rehearing or reconsideration is denied.

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[40] Coalition and CUB Response to Applications for Rehearing or Reconsideration at 25, n 91 (citing DCC Application, at 33; Order 26-154, at 66; Coalition/400, Souder/46–48).
[41] OAR 860-001-0080. Qualified parties to a contested case in which material is filed subject to a protective order may access protected information by signing the protective order.
[42] OAR 860-001-0070.

L. Postponement of Compliance Filing

1. Order No. 26-154 and Compliance Filing

In Order No. 26-154, we directed PGE to submit a compliance filing at the conclusion of this case by updating its rates consistent with our determinations in the order and the revenue requirement approved in its last general rate case and annual update tariff. We found that it would not be appropriate to defer the advent of lower rates for residential and small commercial customers to an unknown future date.

On June 3, 2026, the company filed Advice No. 26-24 to comply with Order No. 26-154. Staff recommended that the Commission suspend Advice No. 26-24 to allow additional review by Staff and stakeholders. At its public meeting on June 9, 2026, the Commission adopted Staff's recommendation. PGE submitted errata to Advice No. 26-24 on June 30 and July 2, 2026. At our July 7, 2026 public meeting, we approved Advice No. 26-24, as modified by the June 30 and July 2 errata, effective July 8, 2026.

2. Application for Rehearing or Reconsideration

In its request for rehearing or reconsideration (filed July 6, 2026), DCC argues that the breadth and scope of the compliance filing and the challenged portions justify a stay or postponement of application of the challenged mechanisms as necessary to prevent irreparable commercial, operational, and rate-design harm while reconsideration is pending.

3. Resolution

DCC's request for rehearing or reconsideration includes a request for a stay. At our July 7, 2026 public meeting, we discussed and approved Advice No. 26-24, as modified by the June 30 and July 2 errata, effective July 8, 2026.[43] Staff thoroughly reviewed Advice No. 26-154 and supporting work papers, with collaboration from PGE and feedback from stakeholders, to affirm the accuracy of rates and resolve identified issues, in presenting its recommendation to approve the tariff.[44]

DCC's request for rehearing or reconsideration on this issue does not address the standard for rehearing or reconsideration and is denied. Because PGE's compliance filing was addressed at the Commission's July 7, 2026 public meeting, DCC's request for a stay is moot.

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[43] *See* Order No. 26-239 (memorializing public meeting decision) (July 10, 2026).
[44] *Id.* at Appendix A at 2-3.

M. Approval of Schedules 89 and 90

1. Order No. 26-154

Order No. 26-154 directed changes to PGE's rate schedules 89 and 90, as well as creation of Schedule 96.

2. Application for Reconsideration

a. AWEC

AWEC requests reconsideration, arguing that Order No. 26-154 commits an error of law by approving changes to rate schedules that were not filed for revision with the Commission. According to AWEC, in this case, the Commission had no rates or schedules to review aside from Schedule 96 and Rule I, which PGE had attached to its opening testimony. AWEC states that the issue is not only about who is entitled to notice and whether notice was sufficient, but also whether the Commission had jurisdiction to make a finding that a rate or schedule was "fair, just, and reasonable" under ORS 757.210. AWEC claims that the Commission cannot make that determination without the necessary precursor under ORS 757.220 that changes be plainly indicated upon existing schedules, or by filing new schedules with the Commission.

AWEC adds that a rate revision that affects all or most of a utility's rate schedules, as is the case here, is a general rate revision subject to additional regulatory requirements which were not followed in this case. AWEC notes that general rate revisions are subject to special regulatory requirements, such as the obligation for the utility to provide testimony and exhibits, work papers, an executive summary, responses to standard data requests, and a motion for protective order if needed, with the filing of new or revised tariff schedules.

b. The Coalition and CUB's Response

In response, the Coalition and CUB argue that ORS 756.515 grants the Commission the authority to open an investigation whenever it "believes that any rate may be unreasonable or unjustly discriminatory * * * or that an investigation of any matter related to a public utility or telecommunications utility or other person should be made." When acting pursuant to a self-initiated investigation, the Commission may issue "the same orders * * * as if such investigation had been made on complaint." In addition, they note that while OAR 860-022-0017 defines a general rate revision as a "filing by an energy or large telecommunications utility which affects all or most of a utility's rate schedules," that the exceptions to that definition of a general rate revision indicate that PGE's filing in this case does not constitute a general rate revision: Excluded from the definition of a general rate revision are changes in an automatic adjustment clause, changes in the credit reflected on rate schedules relating to section 5(c) of the Northwest Power Act, "or similar changes in one rate schedule * * * that affects other rate schedules." In adopting the latter exceptions, the Coalition and CUB explain the Commission has stated that "changes to one tariff * * * that in turn affect a number of other tariffs are now excluded. It has been unclear in such circumstances whether notice of such changes was necessary." Finally, the Coalition and CUB point out that the changes made to PGE's schedules were noticed to the Commission on June 3, 2026, and that more than 30 days passed before the changes took effect on July 8, 2026.

c. PGE Response

PGE similarly notes that if the proposed rate schedule changes do not turn on a change in the schedules but rather have the consequence of one rate schedule "affecting" other rate schedules, the utility filing does not constitute a general rate revision. PGE points out in addition that Order No. 26-154 directed PGE to implement changes in a compliance filing and ordered PGE to "file new tariffs consistent with this order," but it did not preemptively approve the rate schedules that would follow. Instead, the Commission's approval came after PGE filed Advice No. 26-24 on June 3, 2026, which the Commission suspended "to ensure that Staff and stakeholders have sufficient time for review." Finally, PGE argues that when PGE filed its new Schedule 96 and changes to Rule I with its direct testimony, it was clear that the Commission's ultimate decisions on those rate schedules would have implications on "all customer classes" and the rate schedules for each one of them.

3. Resolution

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 all 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.

The POWER Act was adopted by the Legislature on June 5, 2025, and was signed and became effective on August 25, 2025. As we explained in Order No. 26-154, this investigation was opened before the POWER Act was passed; it 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. An extensive record was then developed on the proposed changes to Schedules 89 and 90, as well as the creation of Schedule 96 and revisions to Rule I. The parties to this proceeding filed opening testimony on August 11, 2025; there were a further two rounds of simultaneous written testimony, followed by an evidentiary hearing conducted by the Commission on January 21, 2026.

Order No. 26-154 did not, as AWEC would have it, find that PGE's revised rate schedules were just and reasonable; as AWEC correctly notes, PGE's revised rate schedules had yet to be filed at the time that order was issued. Rather, we found in Order No. 26-154 that certain changed approaches to PGE's rate schedules and rules were just and reasonable, and directed PGE to implement those changes. After extensive Staff and stakeholder review, at our July 7, 2026 public meeting, as memorialized in Order No. 26-239, we approved PGE's implementation of our directives in its revised rate schedules.

Nor were PGE's changes to its rate schedules required to be filed as a general rate case. As CUB, the Coalition, and PGE point out, if the proposed rate schedule changes turn on one rate schedule "affecting" other rate schedules, the utility filing does not constitute a general rate revision. The simple fact of the creation of Schedule 96, leaving aside the requirements of the POWER Act, necessitated a change in how PGE's existing revenue requirement is allocated among rate classes. This proceeding—which did not alter PGE's revenue requirement—presents a prime example of our rules' exemption from the definition of a general rate case.

AWEC has not demonstrated an error of law essential to our decision; its application for reconsideration is denied. As discussed below, however, we grant reconsideration and clarification with respect to discrete issues raised by AWEC related to Schedules 89 and 90.

N. Minimum Demand Charges for Schedules 89 and 90.

1. Order No. 26-154

In Order No. 26-154, we noted that 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 found that protecting against unwarranted cost shifting is necessary to ensure rates are just and reasonable. Accordingly, we found that 90 percent MGD and MTD charges are appropriate for Large Load Customer Agreements[45] customers on Schedule 90 as well as Schedule 96. We based this finding on the fact that customers taking service under Schedule 90 must be of a certain size and maintain a load factor of at least 80 percent, which we found sufficiently similar to the characteristics of data centers to justify the same MGD and MTD charges.

Noting a dearth of evidence in the record regarding the appropriateness of either increasing Schedule 89 customers' MTD charge from 80 percent to 90 percent or adding an MGD charge of any amount for these customers, we did not authorize such changes with respect to Schedule 89, and instead directed PGE to support any proposed changes to minimum demand charges for Schedule 89 customers in its next rate case.

2. Application for Reconsideration

AWEC requests reconsideration. AWEC notes that in docket UE 430, we suspended PGE's filing[46] for investigation and hearing and invited PGE to file a revised tariff "subject to the condition the tariff specify that for any Customer Service Contracts signed after the tariff effective date, all contract terms would be subject to change, pending the outcome of our investigation in this docket and the investigation addressed below," [47] *i.e.*, docket UM 2377. AWEC states that we allowed the pre-Order No. 26-154 version of Rule I to go into effect only on a temporary basis subject to the evidentiary decisions that

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[45] *See* PGE Tariff, Rule I.

[46] *In the Matter of Portland General Electric Company, Investigation into New Load Connection Costs*, Docket No. UE 430, Initial Utility Filings, Advice No. 24-38 (Dec. 20, 2024) (supplemented Feb. 14, 2025, and Feb. 21, 2025).

[47] *Id.*, Order No. 25-091 at 1 (Mar. 6, 2025); *see also* Third Supplemental Filing of Advice No. 24-38 (revised tariff sheets specifying that any customer service contract signed after the tariff effective date are subject to change pending Commission final orders in Commission Docket Nos. UE 430 and UM 2377) (Apr. 1, 2025).

were deferred to this proceeding. AWEC contends that we thus never made a final determination in docket UE 430 based on record evidence that minimum demand charges at any level were just and reasonable for any customer class. AWEC argues that, given that we found no record evidence to support increasing Schedule 89 customers' MTD charge from 80 percent to 90 percent, minimum demand charges should be wholly removed from Schedule 89 as there is no record evidence to support such charges.

AWEC argues, with respect to Schedule 90, that while the order finds appropriately that the Commission has a general statutory obligation to ensure just and reasonable rates and that protecting against unwarranted cost shifting is necessary to ensure rates are just and reasonable, Order No. 26-154 does not explain why those obligations justify imposing minimum demand charges on Schedule 90 customers and cites to no record evidence to support its conclusion. AWEC states that the only evidence we cite in support of our finding that Schedule 90 customers are sufficiently similar to data centers to justify imposing the same minimum demand charges is Schedule 90's size and load factor requirements. According to AWEC, these requirements have remained the same since Schedule 90 was implemented and the Commission has never found that these requirements result in cost shifting to other customers. AWEC states that the Commission must explain any inconsistency with prior agency practice.

3. Resolution

We grant reconsideration. We agree that additional record development is appropriate to determine the minimum demand charges for the Schedule 89 and 90 customer classes. We find additional record development on this issue is most appropriately addressed in PGE's pending general rate case, docket UE 473. We expect the parties in that docket to develop a record sufficient to support a determination as to minimum demand charges for non-data-center large customers. Pending resolution of this issue in the rate case, we retain temporary minimum demand charges for Schedules 89 and 90 as implemented in docket UE 430. PGE is directed to submit revised Rule I consistent with this directive, subject to the condition that for any Customer Service Contract signed after the tariff effective date, all contract terms are subject to change pending and based upon the final order in docket UE 473.

O. Exceedance Penalties for Schedules 89 and 90

1. Order No. 26-154

In Order No. 26-154, we found that no party has justified applying the exceedance penalty proposed for Schedule 96 to Schedule 89 and 90 customers. Accordingly, we directed PGE to include exceedance penalty provisions consistent with the then-effective Rule I in Schedules 89 and 90, resulting in no change from the status quo for Schedules 89 and 90.

2. Application for Reconsideration

In its request for reconsideration, AWEC argues that Order No. 26-154 simply carries forward the Rule I language that was adopted in docket UE 430 on a temporary basis and does so without record evidentiary support.

3. Resolution

As AWEC points out, Order No. 26-154 continues the temporary status quo set in docket UE 430. We agree that additional record development is appropriate on this issue. We therefore grant reconsideration in part and direct that exceedance penalties for Schedules 89 and 90 should be addressed in PGE's pending rate case, docket UE 473. Consistent with the above, the temporary approach will be maintained subject to further record development and resolution in docket UE 473.

IV. ORDER

IT IS ORDERED that:

1. Verrus, LLC's motion for clarification is granted. Verrus, LLC's application for reconsideration is granted.

2. The Alliance of Western Energy Consumers' application for rehearing or reconsideration is granted in part and denied in part.

3. Amazon Data Services' application for rehearing and reconsideration is denied.

4. The Data Center Coalition's application for rehearing and reconsideration is granted in part and denied in part.

5. Portland General Electric Company must file new tariffs consistent with this order no later than September 15, 2026.

6. Portland General Electric Company must address in its pending request for a general rate revision, docket UE 473, the issues of minimum demand charges and exceedance penalties for schedules 89 and 90.

Made, entered, and effective Aug 31 2026.

Letha Tawney
Chair

Les Perkins
Commissioner

Karin Power
Commissioner

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.