October 1, 2026

via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER,
Advice No. 25-015, Schedule 401- Service to New Large Energy Use Facilities
OPUC Docket No. UE 463

Dear Filing Center:

Please find enclosed the Data Center Coalition's Notice of Opposition in the above-referenced proceeding.

If you have any questions, or need anything further, please do not hesitate to contact me.

Sincerely,

Sidney Villanueva

Sidney Villanueva
Blue Skies Law, LLC

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 463

In the Matter of PACIFICORP, dba PACIFIC POWER, Advice No. 25-015, Schedule 401 - Service to New Large Energy Use Facilities	)	DATA CENTER COALITION'S NOTICE OF OPPOSITION

I. INTRODUCTION

The Data Center Coalition ("DCC") supports meaningful protections against inappropriate cost shifting and stranded-cost risk associated with new Large Energy Use Facilities ("LEUFs"). But those protections do not displace the ordinary rules of utility regulation. Data centers remain utility customers entitled to rates and terms that are fair, just, and reasonable, grounded in cost causation, and administered consistently with Oregon's existing statutory protections. Protecting existing customers and establishing fair rates for large customers are complementary—not competing—objectives.

The September 16, 2026 Stipulation materially improves PacifiCorp's original Schedule 401 proposal in several respects. It moves important terms into the tariff, establishes Commission review of LEUF Agreements, provides a mechanism to resolve negotiations that remain unresolved after completion of a service study, creates certain limits for existing customers, and adds reporting and other guardrails. Importantly, DCC does not ask the Commission to discard those improvements. But the Stipulation still leaves unresolved several

issues that go to the heart of whether Schedule 401 is lawful and whether its cumulative financial obligations are supported by the costs and risks PacifiCorp actually faces.

As a threshold matter, DCC recognizes that the Alliance of Western Energy Consumers ("AWEC"), Amazon Data Services ("ADS"), Rowan Percheron, and Vitesse do not oppose the Stipulation, and DCC does not discount the significance of that posture. At the same time, non-opposition by individual large-load customers or customer representatives is not the same as an affirmative determination that each provision of Schedule 401 is lawful, cost-based, or appropriately calibrated. That distinction is important because the Joint Testimony relies in part on the absence of opposition from data-center parties as support for approval of the Stipulation. DCC represents a broader coalition of data-center operators and has identified concerns with the cumulative operation of provisions that may affect customers differently depending on their service configuration, infrastructure needs, and contractual circumstances. DCC's opposition therefore does not suggest that the positions of AWEC, ADS, or Vitesse are misplaced; it identifies discrete legal and ratemaking issues that remain for the Commission to resolve notwithstanding those parties' decision not to oppose the negotiated package.

The central problem with the Stipulation is not any single protection viewed in isolation. Schedule 401 can require a New LEUF to fund Network Upgrades upfront; pay an OATT-based Peak Demand Charge; pay for generation and storage through a Reservation Charge or direct reimbursement structure; remain subject to other Schedule 401 surcharges; post security sufficient to cover an Exit Fee; pay the Exit Fee upon early departure; and, for customers over 100 MW, pay a new Community Energy Benefits Charge. As described in more detail below, the Commission should require the proponents to identify what cost or risk each layer addresses after

accounting for the others, and to provide enforceable credits or limitations where the same investment, capacity responsibility, or risk is otherwise captured more than once.

That inquiry is particularly important because the supporting testimony itself recognizes that upfront customer funding can substantially eliminate the very risks invoked to justify additional protections. Environmental Intervenors' witness explains that when costs are paid upfront through CIAC, "the risk of cost-shifting or stranded assets is greatly reduced and, arguably, eliminated." The same testimony describes the Exit Fee as a backstop for infrastructure that remains unpaid. Those propositions should matter to the design of the rest of Schedule 401.

DCC also maintains the threshold legal objections that have been raised throughout this proceeding. The POWER Act added requirements for service to LEUFs; it did not repeal Oregon's existing cost-of-service, filed-rate, nondiscrimination, and just-and-reasonable-rate statutes. Nor did it rewrite HB 2021 to shift the utility's system-wide emissions-reduction obligations to an individual customer class. DCC recognizes that the Commission recently reached different conclusions on certain analogous issues in UM 2377. DCC does not concede that those conclusions are correct and does not waive any administrative or judicial challenge to them. At the same time, DCC offers narrower alternatives below so that the Commission can correct the most immediate defects in Schedule 401 even if it does not resolve every statutory issue in DCC's favor here.

DCC therefore respectfully requests that the Commission decline to approve the Stipulation as filed and instead require the following modifications or further process:

1. Require PacifiCorp to offer New LEUFs a transparent stated cost-of-service rate option, while preserving lawful special or non-standard contracts for circumstances that warrant individualized treatment. Alternatively, direct PacifiCorp to establish

such an option in its next general rate case or by a date certain, without treating that future review as a waiver of DCC's present legal objection.

2. Modify the transmission cost-allocation provisions to prevent over-allocation and duplicative allocation, including by requiring appropriate credits or exclusions where the same LEUF load is used to directly assign Network Upgrade costs and is also used to allocate embedded transmission costs through the Peak Demand Charge.
3. Expressly limit the Exit Fee and associated collateral to PacifiCorp's actual remaining, unrecovered stranded-cost exposure after accounting for amounts already reflected in the Stipulation's net-book-value calculation and for any additional prior recoveries, reuse, replacement load, salvage value, avoided costs, and other reasonable mitigation.
4. Reject the one-cent-per-kWh Community Energy Benefits Charge unless and until the Commission determines the scope of the programs to be funded and establishes a supported revenue requirement. At minimum, require transparent accounting, eligible-expenditure rules, reconciliation, reporting, and treatment of overcollections.
5. Narrow the HB 2021 and resource-eligibility provisions so that Schedule 401 does not transform PacifiCorp's statutory compliance obligations into open-ended customer obligations, and require objective methodologies for any customer-specific emissions responsibility.
6. Preserve the Stipulation's protections for existing contractual service and ensure that any new obligations imposed on an existing customer apply prospectively to properly attributable incremental service, costs, or risks.

If the Commission concludes that any material modification cannot be made on the present record or without invoking the Stipulation's withdrawal provisions, provide focused and expedited further proceedings on the disputed terms while preserving the portions of the settlement that are not contested.

II. BACKGROUND

PacifiCorp initiated this proceeding by proposing Schedule 401 as a direct-contracting framework for New LEUFs. DCC supported the creation of a distinct LEUF class and supported additional safeguards against demonstrable incremental costs and stranded-cost risk. It opposed, however, making individually negotiated contracts the exclusive vehicle for establishing the rates and fundamental terms of service for data centers. DCC instead recommended a standardized tariff framework with transparent baseline rates and terms, coupled with special contracts for customer-specific circumstances. For shared generation and network transmission costs, DCC proposed a "higher-of" framework that would protect existing customers against cost shifting while at the same time avoiding duplicative cost allocation to LEUFs when the same increment of load is used both to assign new investments and to allocate embedded system costs.

The Stipulation now requires New LEUFs to execute a LEUF Agreement to receive service. Standard agreements are subject to a 90-day Commission review, non-conforming agreements to a 180-day review, and either PacifiCorp or the customer may submit an unexecuted agreement for Commission resolution if negotiations remain unresolved 180 days after the service study. These provisions materially improve the transparency and reviewability of PacifiCorp's original proposal, but they do not establish a stated cost-of-service rate and they do not require PacifiCorp to complete the service study within any specific period.

The Stipulation also establishes a new set of cost-recovery and risk-mitigation requirements. Network Upgrades generally must be paid for upfront unless they meet a three-part definition of a Qualified Network Upgrade. Qualified Network Upgrades are recovered over time based on PacifiCorp's presently known capacity need. New LEUFs also pay an OATT-based Peak Demand Charge on the customer's highest monthly demand. Generation and storage costs are recovered either through a Reservation Charge based on Contract Demand or through a customer-resource structure that includes direct reimbursement, a Portfolio Risk Management Charge, and a System Firming and Balancing Charge. The Stipulation further establishes an Exit Fee, collateral requirements tied to that Exit Fee, an A&G/shared-cost surcharge, and the one-cent-per-kWh Community Energy Benefits Charge for LEUFs over 100 MW.

DCC's opposition is targeted to meaningful revisions where the Stipulation's framework remains lacking. DCC does not oppose the Stipulation simply because PacifiCorp's framework differs from PGE's framework in UM 2377, nor does DCC ask the Commission to import more restrictive portions of UM 2377 into this case without a fulsome review of their effect on the overall settlement as negotiated. The relevant questions are whether the PacifiCorp-specific provisions embodied in the Stipulation comply with Oregon law, whether the costs and risks assigned to a LEUF are demonstrably attributable to that customer, whether associated benefits and mitigation have been appropriately considered, and whether the cumulative package avoids overlapping, duplicative, or otherwise unsupported recovery.

III. LEGAL STANDARD

A settlement does not displace PacifiCorp's burden or the Commission's independent obligation to determine that the resulting rates and terms are lawful, in the public interest, and fair, just, and reasonable. ORS 757.210(1)(a) authorizes the Commission to determine whether a

new rate or schedule of rates is fair, just, and reasonable. OAR 860-001-0350 likewise provides a mechanism for parties to object to a stipulation and confirms that a stipulation is not binding on the Commission.[1]

The Commission recently described its review standard in Order No. 26-084.[2] Settlements are reviewed holistically, but when a party opposes a settlement the Commission reviews the issues pursued by that party and considers whether the technical, legal, or policy information presented shows that the settlement is not in the public interest, will not produce just and reasonable rates, or is otherwise contrary to law. The Commission also confirmed that the stipulating parties must present evidence sufficient to support adoption.

Additionally, the Commission need not defer to a stipulation merely because several parties have signed it. In Order No. 15-060,[3] the Commission explained that its independent review obligation does not require deference, and thus the Commission does not consider itself bound by a stipulation, and may adopt, reject, or modify its terms as necessary. In Order No. 15-054, the Commission rejected an all-party stipulation where material provisions lacked adequate evidentiary support, while encouraging the parties to preserve the noncontroversial portions through a partial stipulation.[4] The Commission has also modified an otherwise adopted

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1 OAR 860-001-0350(8) ("Within 15 days of the filing of a stipulation, a party may file written objections to the stipulation or request a hearing."); OAR 860-001-0350(9) ("A stipulation is not binding on the Commission.").

2 *In the Matter of Portland General Electric Co., Advice No. 25-31, Schedule 151, Wildfire Mitigation, 2024 O&M Expenses*, Docket No. UE 461, Order No. 26-084 at 2-3 (Mar. 18, 2026). The same standard appears in PacifiCorp's 2024 PCAM order. *In the Matter of PacifiCorp, 2024 Power Cost Adjustment Mechanism,* Docket No. UE 453, Order No. 25-442 at 3-4 (Nov. 13, 2025).

3 *In the Matter of PacifiCorp, Transmission Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 2-3 (Feb. 24, 2015).

4 *In the Matter of Avista Corp., Request for a General Rate Revision*, Docket No. UG 284, Order No. 15-054 at 4-6 (Feb. 23, 2015).

stipulation by removing a discrete provision when the targeted modification addressed the identified concern without disturbing the balance of the remaining agreement.[5]

That is the posture DCC asks the Commission to take here. DCC's objections do not require rejection of every compromise reached by the Stipulating Parties. But an "integrated" settlement cannot insulate unsupported terms from the Commission's statutory review. Paragraph 40 of the Stipulation itself anticipates that the Commission may reject or materially condition all or part of the settlement and sets out the parties' rights if that occurs. The Commission should therefore resolve the disputed legal and ratemaking questions presented here and provide whatever additional process is necessary to implement its decision.

IV. ARGUMENT

A. The POWER Act Must Be Applied Together with Oregon's Existing Utility Statutes, Not as a Replacement for Them.

1. Schedule 401 should include a stated cost-of-service rate option before it becomes effective.

The POWER Act directs the Commission to establish a separate LEUF classification with its own tariff schedule and authorizes proportional allocation or direct assignment of costs. It also requires a contract for service to a New LEUF. But those provisions must be read together with the statutes that already govern Oregon electric service. ORS 757.210 expressly contemplates Commission review of a "rate or schedule of rates"; ORS 757.230 requires comprehensive service classifications; ORS 757.310 and ORS 757.325 prohibit unlawful differences, preferences, and disadvantages; and, most directly, ORS 757.603 requires an electric

[5] *In the Matter of Portland General Electric Co., Request for a General Rate Revision, 2024 Annual Power Cost Update*, Docket No. UE 416, Order No. 23-477 at 7-8 (Dec. 18, 2023).

company to provide retail customers connected to its distribution system with a regulated cost-of-service rate option unless the Commission grants a statutory waiver after the required process.

Nothing in the POWER Act expressly repeals or suspends those requirements. The statutory provisions can readily operate together. A LEUF can execute a contract that implements tariffed service—addressing interconnection, contract demand, term, collateral, direct assignment, and other project-specific matters—without making the rate for basic utility service itself a privately negotiated term. Indeed, that is the ordinary distinction between a tariff and a special contract. The POWER Act's express preservation of special contracts, direct access, green power rates, and voluntary renewable tariffs reinforces that these are available service options, not a direction to eliminate the regulated cost-of-service option.

The Stipulation improves transparency by standardizing many contract terms, but it does not cure the threshold problem. The ultimate price of service still depends on an individualized agreement rather than a stated Commission-approved cost-of-service rate available to the class. That matters not only for statutory compliance but also for comparability, administrability, and bargaining leverage in an exclusive service territory. A customer should not have to accept disputed commercial terms simply to preserve its place in the process for obtaining utility service.

DCC therefore asks the Commission to require PacifiCorp to offer a transparent stated cost-of-service option while preserving special or non-standard contracts where justified. If the Commission declines to resolve that question now, it should at minimum direct PacifiCorp to establish and support a stated cost-of-service rate in its next general rate case or by a date certain, whichever occurs first. That alternative relief should not be treated as a waiver of the present statutory objection.

2. HB 2021's system-wide utility obligations should not become open-ended customer obligations.

The same statutory-construction principle applies to HB 2021. The POWER Act requires the Commission to consider whether LEUF rates impede an electric company's ability to meet Oregon's clean-energy targets and whether the tariff allows procurement or contracts that support compliance. It does not state that the utility may transfer its system-wide emissions-reduction obligation to an individual customer as a condition of service. HB 2021 itself supplies mechanisms for circumstances in which compliance would threaten reliability or fair, just, and reasonable rates, including the temporary-exemption and compliance-cost-cap provisions in ORS 469A.440 and ORS 469A.445.

Paragraph 21(f) goes further. If existing emitting resources serve a New LEUF, the customer becomes responsible for emissions reductions associated with electricity delivered to other Oregon PacifiCorp customers so that the LEUF does not increase PacifiCorp's emissions or shift HB 2021 compliance costs. Yet the Stipulation does not establish an objective methodology for identifying the emissions obligation, valuing the required reductions, crediting customer-provided resources, or determining when that responsibility ends. Paragraph 33 separately makes any resource participating in a formal PacifiCorp procurement in any state unavailable to support a LEUF, regardless of whether the procurement is actually relevant to Oregon service.

DCC does not oppose clean-resource objectives or reasonable customer responsibility for demonstrable incremental costs caused by LEUF service. But those objectives should be implemented through the statutes the Legislature enacted. The Commission should not repurpose Schedule 401 into an alternative HB 2021 compliance mechanism without clear standards and a supported showing of causation. Nor should LEUF customers be subjected to customer-specific

compliance obligations without access to the statutory protections designed to limit unreasonable compliance costs. DCC therefore requests removal or narrowing of the overbroad provisions. At minimum, any emissions responsibility should be calculated under an objective, reproducible methodology, should credit customer-provided non-emitting resources and other mitigation, and should be limited to the demonstrable incremental impact of the LEUF.

B. The Commission Must Evaluate the Stipulation's Cumulative Financial Burden and Both Sides of the Cost-Causation Ledger.

The Stipulation should not be evaluated as a collection of unrelated protections. Each mechanism may be described as addressing a distinct concern, but the ratemaking question is whether the entire package remains proportionate after accounting for what the customer has already funded, what PacifiCorp continues to provide, what risks remain, and what benefits and mitigation reduce those risks. The Commission cannot know whether a seventh layer of protection is necessary without first understanding what the first six have already accomplished.

That cumulative inquiry matters especially here because Schedule 401 can combine upfront customer funding with recurring charges, contingent departure liability, and security obligations. Upfront funding is not the same thing as payment for ongoing operation, ancillary services, or use of the broader transmission system. Conversely, an ongoing charge cannot be justified by capital that the customer has already paid. Rather than assume all costs and charges must be understood now, the Commission should require PacifiCorp to separate those categories and identify the residual cost or risk addressed by each mechanism when submitting a LEUF Agreement for review.

Illustrative reconciliation the Commission should require

Mechanism	Stated function	Question for reconciliation
Network Upgrade funding	Recover customer-caused facilities	What portions are needed for sole use and shared, or later useful to others, and what credit applies?
Peak Demand Charge	Compensate use of existing transmission system	What embedded transmission responsibility remains after direct assignment and what load is used to allocate embedded costs?
Capacity Reservation Charge	Charge for Excess Reserved Capacity	What residual underutilization or stranded asset risk remains after upfront funding and other protections?
Reservation Charge / resource reimbursement	Recover generation, storage, and related facilities/services	Which costs are capital, which are ongoing, and how are overlaps with other charges prevented?
Exit Fee	Protect against unrecovered costs on early departure	What amount actually remains unrecovered after prior payments and mitigation? Has is it been reduced for expected system use?
Collateral	Secure payment of Exit Fee	How does security decline as the underlying exposure declines?
A&G/shared-cost surcharge	Recover administrative and other shared costs	Are these costs already embedded elsewhere, and how are additions reconciled?
Community Energy Benefits Charge	Fund specified public-benefit programs	What program budget or revenue requirement supports collection of the one-cent rate?

A complete cost-causation analysis must also consider benefits. DCC's rebuttal testimony explains that cost-effective new load can spread fixed system costs over a larger billing base, contribute revenues to public-policy riders, support new infrastructure, and provide other system benefits. The proper question is not whether every proposed LEUF will deliver every possible benefit. It is whether the Commission is measuring net cost and net risk against unique benefits rather than treating every potential cost as certain while treating offsetting revenues, customer-funded resources, future shared use, and other benefits as unquantifiable or irrelevant. An analysis that considers only risk is not a complete cost-causation analysis.

Paragraph 20(a) of the Stipulation requires PacifiCorp to describe how each LEUF Agreement avoids double-counting costs. That requirement is useful but does not establish a substantive standard against which the Commission should evaluate overlapping cost recovery, nor does it specify what happens if the same customer load, investment responsibility, or risk is reflected in more than one charge. A narrative explanation that two mechanisms are labeled differently does not automatically demonstrate that their combined application is cost causal.

DCC does not ask the Commission to create an entirely new obligation. Rather, it asks that the Commission give Paragraph 20(a) practical effect by requiring PacifiCorp to identify, for each potentially overlapping mechanism, the distinct cost or risk being recovered and to demonstrate that the same cost responsibility has not already been assigned elsewhere. Where the customer has already funded an investment directly, or where the same increment of load has already been used to assign responsibility for new facilities, PacifiCorp should identify what residual embedded-system cost or stranded-cost risk remains before imposing an additional charge based on that same load or investment.

And the requirement should have a corresponding remedy. If PacifiCorp cannot demonstrate that the second mechanism recovers a distinct, unrecovered cost or risk, the LEUF Agreement should provide an appropriate credit, exclusion, reduction, or other adjustment so that the customer is not allocated the same responsibility through multiple pathways. Without such a standard and remedy, Paragraph 20(a) risks functioning primarily as a disclosure requirement. With them, it becomes an enforceable protection against the duplicative or overlapping allocation that DCC has identified.

The Commission should therefore require a reconciliation for each LEUF Agreement and in the next Schedule 401 review identifying: (1) customer-funded investments; (2) PacifiCorp-

funded investments; (3) embedded-system charges; (4) ongoing service costs; (5) contingent stranded-cost exposure; (6) security supporting that exposure; (7) credits, reuse, and replacement-load mitigation; and (8) incremental revenues and other measurable system benefits. That is the information needed to determine whether the cumulative package contemplated in the Stipulation protects other customers or simply transfers additional value from one class without a cost basis.

C. The Transmission and Capacity Provisions Require Specific Reconciliation to Avoid Over-Allocation.

1. The Qualified Network Upgrade exception can require a LEUF to fund facilities that indisputably serve others.

Paragraph 21 generally requires the New LEUF to pay upfront for any Network Upgrade required to serve its load, but also establishes circumstances in which a LEUF is required to pay more than needed to provide its service. A shared transmission facility qualifies for proportionate treatment only if, among other things, LEUF demand is less than 80 percent of PacifiCorp's presently known capacity need. The supporting testimony illustrates the consequence.[6] If PacifiCorp constructs a 1,000 MW Qualified Network Upgrade, a LEUF needs 400 MW, and non-LEUF customers need 200 MW, the LEUF pays approximately 67 percent of the cost over time. But if non-LEUF need is only 100 MW, the LEUF represents exactly 80 percent of presently known need and the facility loses Qualified Network Upgrade status. The testimony states that the LEUF would then pay the full cost of the 1,000 MW facility upfront.

These examples expose two flaws in the proposed allocation. First, even when the facility qualifies for proportionate treatment, the formula assigns the LEUF 67 percent of a 1,000 MW facility's cost based on its 400 MW need. It allocates the cost of capacity beyond the LEUF's

[6] Stipulating Parties/100, Meredith-Stevens-Tran-Fisher/26.

identified need according to the relative shares of presently known demand, without separately evaluating who will benefit from that additional capacity.

Second, the 80 percent threshold creates a sharp and unsupported change in treatment. In the second example, PacifiCorp has identified 100 MW of non-LEUF need and constructs a facility with 600 MW of additional capacity beyond the LEUF's 400 MW requirement. Yet the tariff would assign the entire facility to the LEUF. The Commission should require a supported allocation of shared Network Upgrade costs and an enforceable credit for later use by other customers rather than making shared value disappear because a threshold changes from 79.9 percent to 80 percent.

The same principle should govern paragraph 36, which allows a future surcharge when a LEUF accelerates construction of a planned facility. The Commission should require PacifiCorp to identify the actual acceleration caused by the LEUF, allocate only the attributable share, and prevent the accelerated facility from simultaneously producing unreconciled recovery through other transmission mechanisms.

2. Direct assignment plus the OATT-based Peak Demand Charge can over-allocate transmission responsibility even if PacifiCorp removes customer-funded assets from rate base.

PacifiCorp responds to double-recovery concerns by explaining that customer-funded Network Upgrade costs will be removed from the Company's revenue requirement. That is necessary, but it does not fully answer DCC's concern. Removing a specific asset from rate base can prevent collection of the same booked investment through two revenue requirements. It does

not establish that the customer is allocated an appropriate share of the remaining embedded system after its load has already been used to assign incremental investment.[7]

DCC's rebuttal testimony illustrated the principle using a 500 MW new load and a system with 100 MW of existing headroom. If 400 MW of new capacity must be built and assigned to the LEUF, using the entire 500 MW again to allocate embedded-system costs produces responsibility for more capacity than the customer's actual incremental load. DCC therefore recommended that only the portion of load not already used to assign growth-related investment participate in the allocation of embedded system costs. The same principle should be applied to Schedule 401's direct-assignment framework.

The Peak Demand Charge creates an additional concern because it applies the identified OATT rates to the customer's individual highest monthly demand. To the extent the underlying transmission revenue requirement was developed using a system-coincident demand allocator, an individual customer peak can exceed that customer's contribution at the system coincident peak. The result can be an additional over-allocation unless the tariff contains an adjustment. DCC therefore requests that, if any Network Upgrades providing system-wide benefits are directly assigned to a LEUF, the Peak Demand Charge apply only to the portion of LEUF load not deemed served by those directly assigned upgrades, with the treatment of the Schedule 1, Schedule 3, and NITS components separately specified based on their actual cost basis.

Consider the Stipulation's example of a LEUF needing 400 MW of transmission capacity, with another 100 MW of identified non-LEUF need, where PacifiCorp constructs a 1,000 MW Network Upgrade. Under the Stipulation's own supporting example, LEUF demand

[7] *See* Stipulating Parties/100, Meredith-Stevens-Tran-Fisher/22-24.

is 80 percent of presently known PacifiCorp need, so the project would fail the Qualified Network Upgrade test and the LEUF would fund the entire 1,000 MW facility upfront. Paragraph 21(e) would nevertheless assess the OATT-based Peak Demand Charge based on the LEUF's *total* monthly peak demand inclusive of the 400 MW that was the basis for the direct assignment of the 1,000 MW Network Upgrade facility. Further, depending on whether Rule 13's Capacity Reservation Charge ("CRC") remains applicable, the LEUF could also face a CRC when actual demand falls below the Rule 13 threshold. The LEUF would remain subject to the Exit Fee for PacifiCorp-funded infrastructure and to collateral securing that fee. The point is not that each of these items necessarily recovers the same dollar. The point is that the Commission cannot determine whether the package is proportionate without asking what investment or residual risk remains after each preceding protection is applied.

D. The Exit Fee and Collateral Must Be Limited to Actual Remaining Stranded-Cost Exposure.

The Exit Fee is the clearest place to apply a residual-risk principle. Paragraph 21(l) includes the net book value of company-funded infrastructure, the net cost of customer-specific power or tolling agreements, the Reservation Charge for the remainder of the contract, and removal costs. Paragraph 21(h), however, explains that the Reservation Charge itself is designed to recover capital and maintenance costs associated with the facilities and resources required for service over the contract term. If the remaining Reservation Charge contains recovery of the same capital reflected in the net book value component, adding both amounts without an offset risks counting the same principal twice.

The supporting testimony confirms the appropriate purpose of the fee: it is intended to hold a departing customer responsible for "yet unpaid-for infrastructure costs."[8] That is stranded-cost protection, not a guarantee that PacifiCorp will receive every dollar that would have been billed had the customer remained through the end of its contract regardless of mitigation. The Commission reached the same basic limiting principle on reconsideration in UM 2377 when it created a mechanism to reduce PGE's tariff-calculated exit fee if the formula would exceed actual stranded-cost exposure.[9] DCC relies on that principle as an alternative basis for relief here without conceding the validity of the Commission's other holdings in UM 2377.

Schedule 401 should therefore require an explicit net-exposure calculation. To the extent the Stipulation's use of net book value already reflects customer contributions and accumulated depreciation under PacifiCorp's standard ratemaking treatment, those amounts should not be deducted a second time. The relevant inquiry is whether, after applying the ratemaking conventions embedded in the initial calculation, PacifiCorp's remaining exposure is further reduced by prior recoveries, reuse of facilities, replacement-customer revenues, salvage value, avoided future costs, or other reasonable mitigation. The Exit Fee should be limited to that actual remaining unrecovered exposure. The Stipulation's three-year replacement-customer refund is useful and should be preserved, but it is not a complete substitute for measuring PacifiCorp's actual remaining exposure.

Collateral should follow the corrected exposure. Paragraph 29 permits PacifiCorp to require credit support or collateral sufficient to cover the Exit Fee and reassesses that amount every two years. Collateral is security rather than another revenue payment, but excessive

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8 Stipulating Parties/100, Meredith-Stevens-Tran-Fisher/52-53.

9 *See In re PGE, Investigation into Marginal Cost Study Treatment for Large Customers*, Docket No. UM 2377, Order No. 26-309 at 9 (Aug. 31, 2026).

security carries real financing and liquidity costs. If the underlying Exit Fee is overstated, collateral magnifies the burden. The tariff should therefore require timely step-downs as exposure declines and permit reasonable credit alternatives.

E. The Community Energy Benefits Charge Must Be Tied to a Defined Program and Revenue Requirement.

Paragraph 26 imposes a one-cent-per-kWh charge on LEUFs over 100 MW to fund non-cost-effective energy efficiency, enabling repairs, and distributed energy resources for low-income customers. DCC does not question the importance of assisting low-income customers or pursuing appropriate energy-efficiency and distributed-resource programs. The problem is the ratemaking sequence: the Stipulation fixes the price first and leaves the actual program-administration rules for a later docket.

DCC's rebuttal testimony explained that the one-cent amount is not derived from an identified revenue requirement, program budget, or estimate of the costs necessary to achieve the stated objectives. If additional funding is warranted, the Commission should first determine the scope of the programs and the corresponding revenue requirement and then establish a transparent rider designed to recover that amount. That is ordinary rate design: determine the cost to be recovered, then design the rate.

The magnitude illustrates why the sequence matters. A hypothetical 400 MW customer operating at a 90 percent annual load factor would consume approximately 3.154 billion kWh per year. At one cent per kWh, the charge would collect approximately $31.5 million annually from that customer alone—more than $630 million over twenty years before escalation or discounting. Those figures do not establish that the programs should receive no funding; they

demonstrate why a fixed volumetric charge should be tested against an actual funding requirement and reconciled as collections and program needs become known.

DCC recognizes that the Commission recently upheld a similar PGE charge in UM 2377. DCC preserves its statutory and cost-causation objections to that decision and does not ask the Commission to treat it as controlling evidence that PacifiCorp's charge is lawful or properly sized. If the Commission nevertheless retains paragraph 26, it should at minimum require transparent accounting, eligible-expenditure rules, annual reporting, reconciliation to actual program needs, and a mechanism for credits or rate reductions when collections exceed authorized expenditures. The Stipulation's provision reducing the charge to zero following a final judicial determination that PGE's parallel charge is unlawful should likewise be preserved.

F. The A&G and Shared-Cost Surcharge Requires Separate Cost Support and Reconciliation.

Paragraph 21(m) is analytically different from the Community Energy Benefits Charge because it at least begins with a cost-of-service concept: forecast A&G expense from the most recent general rate case divided by forecast sales, plus certain costs later folded into base rates and other shared costs the Commission deems appropriate. DCC does not oppose recovery of demonstrable administrative and shared costs caused by LEUF service. But the breadth of the provision requires guardrails.

PacifiCorp should identify the expense pool included in the calculation, explain why the selected denominator produces a cost-causal allocation, and demonstrate that A&G or other shared costs are not already embedded in OATT rates, project-specific charges, resource arrangements, or another Schedule 401 mechanism. Additions of costs "folded into base rates" or other shared costs should be accompanied by an explicit credit or reconciliation to prevent

overlapping recovery. Escalation between general rate cases should likewise be reconciled when actual cost-of-service information becomes available.

G. Existing Contractual Service Should Be Preserved, and New Obligations Should Apply Prospectively to Properly Attributable Incremental Costs or Risks.

DCC supports the Stipulation's decision not to treat every existing LEUF as a New LEUF. Paragraph 15 excludes paid CIAC from the calculation of significant investment and excludes post-June 16, 2025 maintenance, repair, renewal, and replacement costs needed to continue existing service up to the contract demand in place on that date. Paragraph 16 requires a study, rather than automatic Schedule 401 treatment, when an existing LEUF increases contract demand by at least 10 MW but does not otherwise meet the New LEUF definition. Those protections should remain.

DCC's requested clarification is affirmative rather than open-ended: existing contracts should generally be respected; new Schedule 401 obligations should attach only when a material post-effective-date change creates demonstrable new costs or risks; and any new obligations should apply prospectively to the incremental service or investment at issue. PacifiCorp should not use Schedule 401 to recover costs already paid through CIAC, existing rates, Rule 13, or another mechanism, or to retroactively alter contractual rights that do not themselves create the new cost or risk identified by the POWER Act.

DCC also recognizes that paragraph 25 contemplates a future tariff filing for LEUFs not subject to Schedule 401. In the meantime, DCC asks the Commission to preserve existing contractual rights while any future tariff for existing LEUFs is developed through an appropriate proceeding with transparent cost-of-service support. DCC understands that this is how the stipulation is drafted and should be interpreted.

H. The Commission Should Require a Defined Review of Schedule 401.

The Stipulation is being adopted before the Commission has experience with completed LEUF Agreements under its new architecture. The rates and protections will interact in ways that can be evaluated more reliably after actual agreements, studies, customer contributions, service levels, and collections exist. The Stipulation already requires biennial reporting through the 2040 reporting year and requires a future filing for uniform flexibility compensation. The Commission should use that same principle of reviewability for the core rate design.

DCC therefore requests that the Commission direct PacifiCorp to reevaluate Schedule 401 in its next general rate case or by a date certain, whichever occurs first. That review should include: the availability of a stated cost-of-service rate option; actual and forecast customer-funded investments; Network Upgrade sharing and later system use; Peak Demand Charge revenues; CRC application, if any; Reservation Charges and other resource costs; actual and forecast tax-related charges if any LEUF customer is required to pre-fund potential tax liabilities; Exit Fee and collateral levels; A&G/shared-cost collections; Community Energy Benefits Charge collections and expenditures; and measurable incremental revenues and system benefits associated with LEUF service.

Critically, committing to a future review is not a reason to approve an unlawful provision today. Nor can later calibration necessarily cure harms caused by an initially excessive or unsupported charges. If an unduly burdensome framework discourages new investment, a later reduction may come too late to restore lost opportunities, while the costs of system investment and compliance remain to be borne by the customers who stay. A future review is therefore alternative and supplemental relief, not a substitute for lawful rates and terms in the first instance. But where the Commission concludes that a particular mechanism may lawfully be

used and the present record does not permit precise calibration, a defined review date is preferable to allowing a first-generation framework to become effectively permanent by inertia.

V. CONCLUSION

DCC supports the core goal of protecting existing customers from unwarranted cost and risk shifting. But the POWER Act did not suspend Oregon's ordinary ratemaking statutes, eliminate the regulated cost-of-service option, or transfer PacifiCorp's system-wide HB 2021 obligations wholesale to one customer class. Nor does cost-shift protection justify cumulative charges and protections that are not reconciled to the costs and risks that remain after customer contributions and other safeguards are taken into account.

The Stipulation is a substantial improvement over PacifiCorp's initial filing, and the Commission can preserve those improvements while addressing the discrete defects identified above. DCC respectfully requests that the Commission require a stated cost-of-service option; correct the transmission allocation; limit Exit Fee and collateral requirements to actual remaining stranded-cost exposure; tie the Community Energy Benefits Charge to a supported funding requirement; narrow the HB 2021 and resource provisions; preserve the Stipulation's protections for existing contractual service; and require a defined review of Schedule 401. If material modifications cannot be made on the existing record or without further action by the Stipulating Parties, the Commission should provide focused further proceedings rather than approving unsupported provisions solely because they appear in an integrated settlement.

These targeted requests preserve the Commission's cost-shift-prevention objective while applying the statutes as written: customers should pay the costs they cause, existing customers should be protected from demonstrable stranded-cost risk, and New LEUFs should not be

charged for costs they do not cause, for the same investment through multiple pathways, or for unsupported public-policy obligations untethered from a defined revenue requirement.

DATED this 1st day of October, 2026.

Respectfully submitted,

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