BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 358

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Advice No. 19-02, New Load Direct Access Program.	OREGON CITIZENS' UTILITY BOARD RESPONSE TO OREGON PUBLIC UTILITY COMMISSION BENCH REQUEST

Pursuant to Administrative Law Judge (ALJ) Moser's September 20, 2019 Bench Request, the Oregon Citizens' Utility Board (CUB) submits the following response in the above-captioned proceeding. Particularly, CUB would like to respond to the first question:

1. Is the sole justification for the proposed RAD the need to procure capacity to provide emergency service and keep the balancing authority (BA) in balance to avoid curtailment when market purchases are unavailable at any price? Or does PGE assert that, when market purchases are available, the current emergency service tariff fails to adequately recover costs such that new load direct access (NLDA) customers will be subsidized without the RAD?
    a. If the latter, please articulate the rationale with specificity.
    b. If the former, please confirm that, if PGE were legally and operationally permitted to curtail NLDA load before cost-of-service load, such differential curtailment would eliminate the need for the RAD?

CUB notes that this question – like most of the Bench Request questions issued on September 20 – seems to be aimed at the Company (*i.e.*, "does PGE assert"), but also recognizes that the Bench Request invited other parties to respond to any or all questions. We will, of course, discuss CUB's position, not our view of PGE's position.

In Reply Testimony, CUB clearly addressed the issue contemplated in the ALJ's question 1 above ("when market purchases are available, the current emergency service tariff fails to adequately recover costs such that new load direct access (NLDA) customers will be subsidized without the RAD?). An excerpt of CUB's Reply Testimony on the issue is provided here:

> CUB believes that the current wholesale market is distorted and changes are necessary to ensure that cost-of-service customers no longer subsidize direct

> access customers. CUB believes that unwarranted cost shifting is currently occurring, as cost-of-service customers pay for the fixed costs of generation, that is necessary to support the market, but direct access customers only pay the variable costs of generation on the market. The fixed costs include the capital costs associated with the generating facility, whereas the variable costs include the fuel. This problem is growing as more resources are renewable, because there are no fuel costs associated with renewable generation – these resources are almost entirely fixed costs. The RIC and the RAD attempt to address this problem. However, by linking the problem to the increasing need for capacity in the region, CUB believes that PGE is understating the problem.[1]

In Reply Testimony, CUB explained that the current market structure is much different than what was envisioned at the time that direct access was established by SB 1149. At the time of SB 1149's passage, California had moved toward full retail deregulation and it was expected that in Oregon new generating resources would no longer be placed in utility rate base,[2] However, full deregulation did not survive in the Western United States. Therefore, utilities continue to procure resources for captive customers—a practice that continues to this day.

In the Northwest, most of the generating assets that serve non-direct access loads are owed by utilities and the federal government or are purchased under long-term contracts by utilities.[3] In order to understand how this distorts the wholesale market, it is worth considering how the market operates currently with utility generation and how the market would operate without utility generation.

Wholesale Market With Utility Generation.

The investment costs—including, but not limited to, the fixed costs—associated with utility generation are paid by captive customers, either through rate base or through long term contracts. However, utilities are still active market participants. At times, a utility may go to the market to procure lower cost resources for its customers and, at other times, a utility may sell excess power to the market and use the revenue to reduce customer rates. This is normal, prudent utility behavior. The decision point on whether to buy or sell to the market is dependent on market prices and marginal generation costs. The marginal generation cost is the variable cost associated with generating a single unit of electricity:

Marginal generation cost ($/MWh) = Marginal cost of Fuel + Variable operations and maintenance costs.

The marginal cost of coal and gas-fired resources is primarily fuel and fuel transportation, although it also includes other variable O&M costs. Renewable generation has no fuel or fuel transportation costs, so its marginal cost is close to zero. Because of federal production-based tax credits, the marginal cost of wind power can even be negative, reflecting the value of the

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[1] UE 358/CUB/100/Jenks 3.
[2] UE 358/CUB/100/Jenks/6.
[3] For the purpose of this bench request, we will refer to resources that are in utility rate base or under long term utility contract as "utility generation."

federal production tax credits associated with each unit of electricity. When the market price is above the marginal cost of a generating asset, and the asset is not needed to serve captive customer load, then the utility will sell into the market. When the market price is below the marginal cost of a generating asset, the utility will purchase from the market rather than dispatch its own generation. This basic economic principle consistently guides utility resource dispatch decision-making.

While the market price of electricity reflects the efficient dispatch of the least cost resource in the market, it does not represent the cost of power for the utility. As discussed, the marginal cost only covers the fuel, fuel transportation, and variable O&M. The cost of power supply includes the fixed costs of generating resources, which includes the cost of the plant site, the generating plant itself, ongoing capital investment necessary to maintain the plant, the cost of financing capital, and the cost of decommissioning the plant after the end of its useful life. For utility-owned generation, these costs are recovered through utility rate base and return on rate base. For a long-term utility purchase, these costs are reflected in the contracted prices under the terms of the contract.

Electricity Service Suppliers (ESSs) that serve the direct access market have a different business model. The power ESSs deliver to direct access customers is "unspecified power" – power that comes from the wholesale market.[4] To avoid the risk of a market disruption that could raise wholesale prices, ESSs engage in financial hedges to reduce their financial risk.

In a wholesale market with utility generation there is a stark difference between what captive utility customers pay (fixed costs of generation plus marginal cost of generation) and what the direct access customers pay (market prices reflecting only the marginal cost of generation).

Wholesale Market Without Utility Generation

SB 1149, which created direct access, did not envision utilities continuing to rate base generation. It still had captive customers, but it envisioned a world where utilities purchased power from the wholesale market on the behalf of residential and small business customers.

In 2019, nearly all generating resources are built by utilities or under long-term contracts for utilities. As stated, captive customers finance the fixed costs of these resources. This is a sign that current market prices would not be enough to recover the fixed capital costs associated with generation. If the utility did not build generation, one of two things would have to happen:

1. Market prices would rise sufficiently to incent generation being built for the wholesale market. Without utility generation, there would be less capacity, more periods of time where capacity constraints created higher prices, and more super-peaks where supply is very tight and market price excursions are substantial. Market participants (utilities and ESSs) would find the cost of financial hedges rise until the point where it was lower cost to invest in power generation as a physical hedge. This could lead to a boom/bust cycle where market participants respond to higher market prices and the higher cost of financial

[4] CUB Exhibit 105.

hedges by building generation, which lowers market prices and the cost of financial hedges, which leads to a period where market participants stop building new generation and again rely on financial hedges and market purchases, causing a tightening supply until beginning a new cycle.

2. The region would find the price variability and the reliability risk associated with constrained supply was too much of an economic risk and would put into place some sort of capacity/resource adequacy requirements. In Reply Testimony, CUB discussed how PJM, the RTO in the Northeast created a capacity market to solve this issue.

In a wholesale market without utility generation, the difference in costs between what utility customers and what direct access customers would pay would be eliminated. Both would pay market prices and capacity/reliability costs. Because the cost of regional capacity would not be solely assigned to utility customers, this market design would lead to lower costs for utility customers and higher costs for direct access customers. In short, utility generation that is financed by captive customers greatly benefits both electricity markets and the region as a whole, and these benefits flow directly to ESSs.

The difference between these two markets: a market with utility generation and a market without utility generation represents the subsidy that is built into our current direct access system. Because direct access was not supposed to require subsidies, the Commission should adopt the RAD to eliminate these subsidies. CUB notes that there are potentially other solutions, such as the PJM requirement that all electric suppliers (utilities and ESSs) develop capacity. CUB is open to exploring other options, but in the meantime, implementing the RAD is necessary to eliminate the subsidy.

CUB is unsure about the feasibility of differential curtailment of NLDA customers. Besides the legal and operational difficulties of PGE curtailing NLDA load before cost-of-service load, economic and political obstacles exist to curtailing NLDA customers. Many industrial centers are major employers in the region, and the curtailment of NLDA load could interrupt the industrial production of these employers. CUB could foresee PGE facing political pressure to keep NLDA customers energized.

In sum, CUB continues to urge the Commission to approve PGE's application in the matter, and adopt the RAD charge to eliminate the subsidization of ESSs and NLDA customers at the expense of captive electricity customers.

Dated this 4th day of October, 2019.

Respectfully Submitted,