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.	)
	)
	)

REPLY TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

July 18, 2019

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.	))))))))	REPLY TESTIMONY OF THE OREGON CITIZENS' UTILITY BOARD

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Bob Jenks. I am the Executive Director of by Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/101.

Q. What is the purpose of your testimony?

A. I respond to arguments raised in the Direct Testimony filed by Portland General Electric Company (PGE or the Company) on June 24, 2019.

Q. Please summarize your testimony.

A. PGE claims that new charges are necessary to ensure that New Load Direct Access (NLDA) customers are paying for the costs associated with providing them service.[1] In this Reply Testimony, CUB examines the Company's claim and explains how the current wholesale market differs from what was envisioned by SB 1149—the bill that began Oregon's direct access program. CUB believes that direct access customers should be required to pay for the capacity necessary for the operation of the grid.

Q. Please describe PGE's proposal.

A. PGE is proposing a New Load Direct Access Program (NLDA), including proposing a new long-term supply option and how PGE intends to manage the current customer queue. CUB's testimony, however, will focus on PGE's proposal to charge direct access customers a Resource Adequacy Charge (RAD) and a Resource Intermittency Charge (RIC) related to the capacity that is necessary to serve their loads.

Q. Please explain the RAD.

A. The RAD is a new charge related to securing the capacity that is necessary to maintain resource adequacy and ensure a reliable grid. Under the RAD, PGE would identify the capacity associated with NLDA customers that is necessary to maintain PGE's resource reliability standard of 2.4 hours of Loss of Load Expectation (LOLE) annually and would charge NLDA customers for this capacity.

Q. Please explain the RIC.

A. The RIC is also a capacity charge, but it relates to the capacity that is necessary for PGE to manage under-scheduling by electricity service suppliers (ESSs) that serve NLDA customers. Based on 2018 data, PGE shows that 40% of the hours during

[1] UE 358 – PGE/100/ Sims – Tinker/11.

the calendar year were under-scheduled.[2] When an ESS under-schedules load, PGE, as the entity responsible for its Balancing Area Authority (BAA), must make up the difference. PGE is proposing to charge ESSs for this capacity during months when they under-schedule. If an ESS does not under-schedule, the ESS would not incur a charge.

II. THE WHOLESALE MARKET IS DISTORTED

Q. Does CUB believe that these charges (the RAD and the RIC) are necessary in order to prevent unwarranted cost shifting?

A. Yes. 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.[3]

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[2] UE 358 – PGE/100/Sims – Tinker/12, lines 15-16.
[3] CUB Exhibit 102.

Q. How does PGE understate the problem?

A. PGE's testimony suggests two problems. The first is under-scheduling of power by the ESSs who serve direct access markets, which requires PGE to maintain capacity to fill in for this under-scheduling. The second is that the Pacific Northwest is capacity constrained, which is causing a need to ensure that direct access customers are contributing to the capacity resources necessary to meet reliability.[4] CUB does not disagree with these points, but believes that they are part of a wider market failure in the west in which the wholesale market is dependent on utility cost-of-service customers covering the fixed costs of generation through retail rates established by the Commission. This would still be a problem even if the region did not face capacity constraints. The current structure is not what was envisioned by SB 1149, the electric restructuring act that allows for direct access. This is not surprising because SB 1149 was designed before the Western Power Crisis, before the Renewable Portfolio Standard (RPS) and before the Coal to Clean Bill (SB 1547). Oregon's electric landscape has changed, and it is time to ask whether changes to Oregon's direct access programs are necessary.

Q. Please explain how the vision of SB 1149 was different that the current market?

A. In the nineties, there was a lot of momentum towards deregulating both wholesale and retail electric markets. Enron, one of the biggest deregulation advocates, had purchased PGE and proposed Oregon deregulate both its wholesale and retail

[4] CUB Exhibit 103.

markets.[5] The idea of deregulation was that electric generation was no longer a function that should be provided by monopolies. Under the deregulation proposal, generation would be provided by a competitive wholesale market. The idea was that a competitive generation market would lead to cost savings and market innovation, that utilities should divest themselves of generation and become wires only companies that distributed power to homes and businesses, and that, with a competitive wholesale market and the utility functioning as a wires-only distribution provider, retail customers should be free to purchase electricity from whomever they wanted. PGE/Enron first proposed this to the Commission in Docket No. UE 102. In UE 102, CUB and Staff proposed alternatives to PGE's full deregulation proposal. The Commission rejected PGE's approach and adopted a plan that contained many of the elements of CUB's and Staff's proposals.[6] However, the Commission stated that if PGE wanted to adopt the Commission plan it would require legislation, which would later become SB 1149.[7]

There are several elements of this PUC-adopted plan which demonstrate that there was a different market structure at the time compared to what has developed:

- The Commission plan allowed all industrial and commercial customers to buy electricity from an Electric Service Provider (ESP)[8] – today referred to as an ESS.

[5] *See* OPUC Docket No. UE 102.
[6] OPUC Order No. 99-033, page 16 (Lexis).
[7] OPUC Order No. 99-033 page 7 (Lexis).
[8] OPUC Order No 99-033, page 7 (Lexis)

- Industrial customers who choose direct access would not be able to return to cost-of-service rates.[9]
- PGE was authorized to divest its non-hydroelectric resources though an auction but prohibited from selling its hydro resources.[10]
- New resources would no longer be placed in utility rate base to earn a return, putting ESPs and PGE on equal footing in making decisions on resource development[11].

The Commission's plan became the basis for SB 1149, Oregon's Electric Restructuring law, which passed in 1999. In many respects, the expectation was that the electric industry would look more like the natural gas industry. Electric utilities would transport electricity to homes and businesses but would not be the developers. With the exception of hydro resources, utilities would procure the resources needed to service residential customers from the wholesale market. Large customers would similarly procure their own power on the market and the utility would only be responsible for delivering the energy to large customers. However, before it could be implemented, the California energy crisis began in 2000 which caused the Western US to pull back from the vision of competitive wholesale markets envisioned by SB 1149.

Q. What changes were made after the California energy crisis?

A. The primary changes were around the issue of resource divestment and, relatedly, the role, size and purpose of competitive markets. As part of California's

[9] OPUC Order No 99-033, page 7 (Lexis)
[10] OPUC Order No 99-033, page 7 (Lexis)
[11] OPUC Order No 99-033, page 7 (Lexis)

deregulation, utilities divested themselves of much of their generation to independent power producers. Utilities then had to buy this power back from these producers on the day ahead market. In 2000, there were accusations of market manipulation. Power prices soared in this short-term market, as utilities became insolvent and as rolling blackouts hit the state.[12] Montana had a similar result after its utility divested itself of generation and pursued retail deregulation.[13] After the failed attempts at deregulation in California and Montana, both pulled back on utility divestment of resources and began having their utilities re-acquire generating resources.

Q. What effect did these changes have?

A. This had the effect of fundamentally changing the nature of the wholesale market. The vision associated with SB 1149 was that utilities would divest themselves of their non-hydro resources, placing these in the hands of independent power producers, and most new power would come from the competitive market. The expectation was that power generation would be independent of utilities and the wholesale market would be where power was bought and sold. However, with California and Montana pulling back from divestment, it meant that most generation was in the hands of traditional utilities and that very little new generation was built by independent power producers to serve the wholesale market. Independent power producers still played a role, but that role was primarily focused on competitive bidding within utility procurement or PURPA

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[12] Public Policy Institute Of California, The California Electricity Crisis: Causes and Policy Options, 2003, forward.
[13] https://scholarworks.umt.edu/cgi/viewcontent.cgi?article=9540&context=etd

projects sold to utilities on long term contracts that covered the investment cost. While there are still a few independent power producer investments that are designed to serve the wholesale market, most power development in the west is done either by a utility or under contract to a utility. This means that the fixed costs associated with generation – the capital costs to build plant – are in the rates of vertically integrated monopoly utilities and are paid for by cost-of-service customers. Some of the generation, such as the Chehalis Generating Facility that was originally developed by independent power producers to serve the wholesale market, instead has been purchased by utilities with the cost put into cost-of-service rates.[14]

Q. What effect has this had on the wholesale market?

A. Utilities use the wholesale market to balance their systems and to identify the least cost resource. However, with utilities as the dominant market producer, wholesale markets do not require prices that allow for recovery of the fixed costs of generating assets, just the variable power costs. RPSs requiring utilities to develop renewable resources further take a step back from the SB 1149 vision. Regardless of whether the utility purchased a renewable resource through a PPA, or it built and ratebased the investments, the RPS required utilities to acquire long term renewable projects, which moves away from a natural gas-like model where power was purchased in short-term markets.

Q. Please discuss how the development of RPS requirements have affected the wholesale market.

[14] OPUC Order No. 10-022.

A. RPS standards require the procurement of renewable resources by utilities. Procurement is primarily done through securing the development of new renewable generation, though a percentage of renewables can be met with unbundled Renewable Energy Certificates (RECs).[15] Several western states, including Oregon, Washington and California have passed RPS requirements and raised those requirements.

RPS resources are different than traditional sources of power because they require large capital investments, but have little operating costs, including no fuel costs. With state laws requiring RPS resources, utilities secure these resources (directly or through power purchase agreement) and place the capital investments or contracts into rates to be recovered from customers. RPS resources, however, are intermittent and non-dispatchable. Rather than being dispatched by the utility to meet load, they generate power when the sun is shining or the wind is blowing. Sunshine and wind often are timed well to meet utility load, but often are not—leaving utilities with excess generation at times. Like any resource, utilities will generally dispatch the excess power to the market when the power is not needed by captive retail customers and the wholesale market price is above the marginal cost of the resource.

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[15] ESS that serve direct access loads have only been required to purchase RECs – though that will change in 2021. However, the concern here is not who is developing renewables, but is the impact that such development has on the wholesale market.

Wind resources are eligible for a production tax credit, a tax credit tied to the volume of power that is produced. The lack of fuel pushes the marginal cost of renewables towards zero. For renewables that are eligible for the production tax credit, the marginal cost is below zero. This means that if I had excess wind that was receiving a $10/MWh production tax credit, I could sell the power to you at a price of negative nine dollars (-$9.00) per MWh and still make a profit of $1 per MWh.

Because power will be dispatched to the wholesale market if the price exceeds the marginal cost of the resource and renewables have marginal costs that are near or below zero, the develop of RPS requirements have reduced the prices in the wholesale market. Today, negative prices regularly occur. The first full year of direct access was 2003. During the first 6 years of direct access, the average on-peak price at Mid-C was $66.42/MWh. During the last 6 years it was cut in half, $32.13.[16] As RPS requirements in the West increase, it will continue to put downward pressure on market prices.

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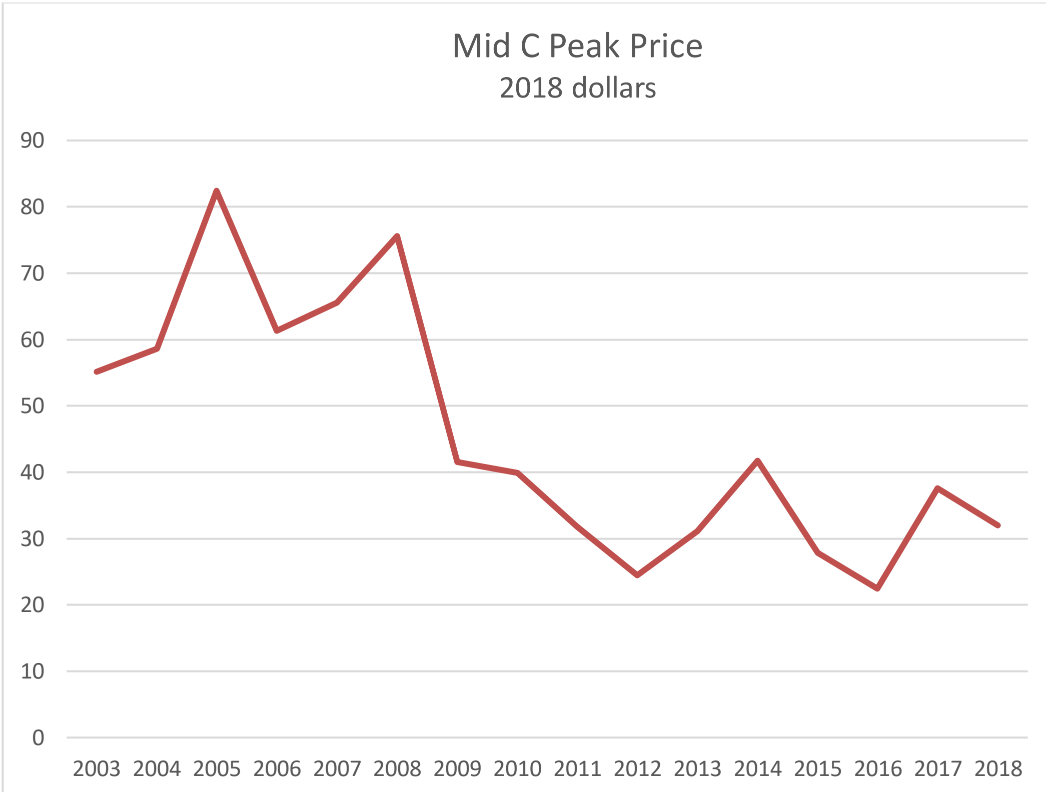
[16] CUB Exhibit 104.



[17]

Q. How would you characterize the wholesale power market?

A. The wholesale power market is subsidized by cost of service customers. Power producers are not building generation to serve the wholesale market. In many respects, wholesale prices primarily serve to provide dispatch signals for generation that is dedicated to serving captive customers. The fixed costs of generation are absorbed by customers of monopoly utilities, but the energy is then dispatched at its marginal cost to serve non-monopoly customers. Without monopoly customers paying the fixed costs under state regulators orders, the resources would not exist to serve the wholesale market.

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[17] CUB Exhibit 104.

In addition, renewable resources, which are driving the price of the market down, are intermittent, are not dispatchable, and do not provide the same contribution to capacity as the resources that were being built before the RPS (i.e., thermal generating facilities). This means the market price resource contributes less to capacity than it used to, just as the region is beginning to have capacity constraints.

Q. Won't this change when ESSs no longer can meet the RPS exclusively with unbundled RECs?

A. Beginning in 2021, ESSs will no longer be able to meet the RPS using only unbundled RECs but will have to meet 80% of its RPS requirements with bundled RECs.[18] On one hand, creating a more level playing field between ESS and utilities with RPS procurement will help. But the prices of renewables have fallen since the RPS was enacted in 2007, so the monopoly utilities had to phase in investments in physical renewables when they were higher priced and the ESS can do it today when costs are lower.

On the other hand, requiring more physical renewables, will put further downward pressure of wholesale market rates so this will further depress market prices. In addition, the renewable requirements that begin in 2021 will require that 16% of energy is supplied with bundled RECs,[19] so the bulk of the power to serve NLDA customers can continue to be served by the short-term wholesale market.

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[18] SB 1547, p 9.
[19] The RPS requirement in 2020 is 20%. (80% of 20% is 16%). This will gradually rise to 40% (80% of 50%).

Currently, most of the power ESS use to serve direct access customers is labeled as unspecified power.[20] Unspecified power is power from the market that is no longer identified as coming from a specific resource. Therefore, even after RPS requirements change and ESS must acquire bundled RECs, much of the power to serve NLDA will come from wholesale market purchases.

Q. What is the current status of wholesale energy market?

A. It is a distorted market that could not exist independently from the marketplace of regulated monopoly utilities. Prevailing wholesale market prices are low. The market clearing price is the marginal-cost which only reflects variable costs, not the capital cost of generating facilities. This price does not support building new generation. If all loads were served by the wholesale market, the electric system would crash because no new generation was being added, even as new load is being added and coal plants are being retired. The reason the current wholesale market works is because utilities' cost-of-service customers continuing to pick up the fixed costs associated with new generation. If utilities did not have captive customers, the structure of markets would have to change to avoid reliability problems associated with not having enough new generation. The market would have to find a way to ensure that capacity was being built and there would be a cost associated with this.

Q. Doesn't economic theory say that the market price should be equal to the marginal cost?

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[20] CUB Exhibit 105.

A. Yes. In a perfect market, the marginal cost of producing the next item would become the clearing price for the market. In this respect, the wholesale market is functioning as a market: the marginal cost of producing the next item sets the clearing price. There are several problems, however.

Market theory normally discusses producers and buyers and a perfect market requires many producers and sellers. In the case of the power market, there are not many producers. Because of the large cost of financing large utility scale power facilities there is a large barrier to enter this market as a producer and this leads to a situation where production is normally financed by a utility directly or through a long-term contract. The utility can afford this barrier because state regulation of monopolies allows it to charge regulated prices and recover the cost of overcoming that barrier to entry. Regulated monopoly prices are not set at the marginal cost of producing the next unit of energy but are set to recover the embedded costs of producing energy,[21] including the capital cost of financing the plant.

The wholesale market developed as a way for utilities to sell surplus power into the market when the price is at or above their marginal cost of production or to buy power when it is priced below their marginal cost of production. This allows for efficiency between utilities. However, a problem arises with the addition of marketers. Marketers simply buy and sell power in the market. They have a low

[21] Oregon uses marginal costs in cost of service studies. But these marginal costs are used to spread embedded costs to classes of customers. Rates are ultimately designed to recover embedded costs.

barrier to entry, because they are not investing in producing facilities. Oregon's direct access program allows them to compete with the utility for large customers. But they are buying power at the utility's marginal cost of producing the next unit of energy (variable power costs), whereas when the utility serves customers, the utility is selling power at its embedded cost (variable power costs plus the fixed costs of financing underlying assets).

The result is that some customers purchase power at regulated prices and some customers purchase it at competitive marginal prices. If we allowed all customers to purchase power at competitive marginal prices, the system would fail because the marginal price of production in the marketplace is not enough to overcome the high barrier to entry and new power supply would not be developed. This is fundamentally a problem of market design and the interaction of a monopoly market and a competitive market.

III. CAPACITY PAYMENTS TO FIX THIS PROBLEM

Q. How would this market function without this distortion?

A. The current western wholesale market is distorted because of the interaction between a regulated market and a competitive market. However, there are other parts of the country that did require utilities to divest resources and did move to a full wholesale market for power supply. Unsurprisingly, the wholesale market has developed mechanisms to account for the fact that the competitive energy market may not be priced at a level that supports the development of new resources or capacity. PJM is the RTO that operates the power market in the Northeast, and it solves this problem by requiring all electric suppliers to have the capacity necessary to meet load:

> In PJM's case, that means that a utility or other electricity supplier is required to have the resources to meet its customers' demand plus a reserve. Suppliers can meet that requirement with generating capacity they own, with capacity they purchase from others under contract, through demand response – in which end-use customers reduce their usage in exchange for payment – or with capacity obtained through PJM capacity-market auctions.
>
> PJM's capacity market, called the Reliability Pricing Model, ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand three years in the future.[22]

In addition to having a short-term energy market, PJM requires load-serving entities to have the capacity to serve customers and looks three years into the future to do so. This is very different that the western power market.

Q. How would PGE's RIC and RAD address this problem?

A. First it is important to note that the West does not have an RTO like PJM that can impose market requirements (such as a capacity procurement requirement) on load serving entities so our solution must be different. PGE proposed RIC and RAD charges are a solution to these problems.

The RAD attempts to establish a capacity requirement like PJM's capacity market. It requires that ESSs contribute to the necessary future capacity that is required to maintain reliability. Where an RTO like PJM is responsible for reliability, the RTO can provide the capacity through a capacity auction and require all market participants purchase capacity. Where the balancing authority and provider of last

[22] https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx

resort is required to maintain reliability, then it needs a mechanism to ensure that all load serving entities within that balancing authority participate. CUB believes that the lack of capacity in the wholesale market is a fundamental problem that must be addressed and that PGE's RAD is a reasonable way to address the problem.

PGE's RIC is a bit different. It is a charge related to the capacity needed today, not in the future. PGE does a good job documenting the problem of ESS regularly under-scheduling power deliveries. This suggests that the ESS does not have enough current capacity to meet its load. Under these circumstances the balancing authority has to step in to ensure that there is enough capacity within the balancing area. The RIC ensures that the balancing authority has the capacity to meets its obligation when the ESS under-schedules its power. If the ESS has enough current capacity to service its load, then it can use that capacity to avoid under-scheduling. CUB supports PGE's proposal and notes that an ESS can avoid these charges by not under-scheduling power.

In CUB's view, there is a serious problem with western power markets. These markets do not include the underlying cost of capacity which is required to develop the resources that are dispatched to the markets. PGE's proposed RIC addresses this capacity problem in the current short-term market and the RAD addresses this problem as it relates to needed future capacity. CUB urges the Commission to adopt these proposals.

Q. Does this conclude your testimony?

A. Yes.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Oregon Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

July 10, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UE 358
PGE Response to OPUC Data Request No. 004
Dated June 26, 2019

Request:

Please refer to PGE/100, Sims – Tinker/8, lines 3 through 8.

a. **In reference to the statement, "the upcoming coal plant retirements at Boardman, Centralia, and Colstrip will remove substantial amounts of firm capacity," please quantify exactly how much capacity will be removed.**

b. **Has PGE performed any independent analysis or study of the risks of resource adequacy specific to its own system? If yes, please provide all evidence, results, and key findings.**

Response:

A. Boardman has an operating capacity of approximately 585 MW. The Centralia units have a combined operating capacity of approximately 1340 MW. Colstrip units 1 & 2 have a combined operating capacity of approximately 614 MW. PGE notes that the above listed plants do not represent an all-inclusive list of retiring units within the WECC.

B. Please refer Chapter 4, specifically Section 4.7, of PGE's 2019 IRP draft available on PGE's website at https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning

July 10, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UE 358
PGE Response to OPUC Data Request No. 001
Dated June 26, 2019

Request:

Please detail how the Company currently handles the issue of an ESS that has under scheduled its load for the hour. Please provide any evidence, and quantify any associated costs when/if applicable.

Response:

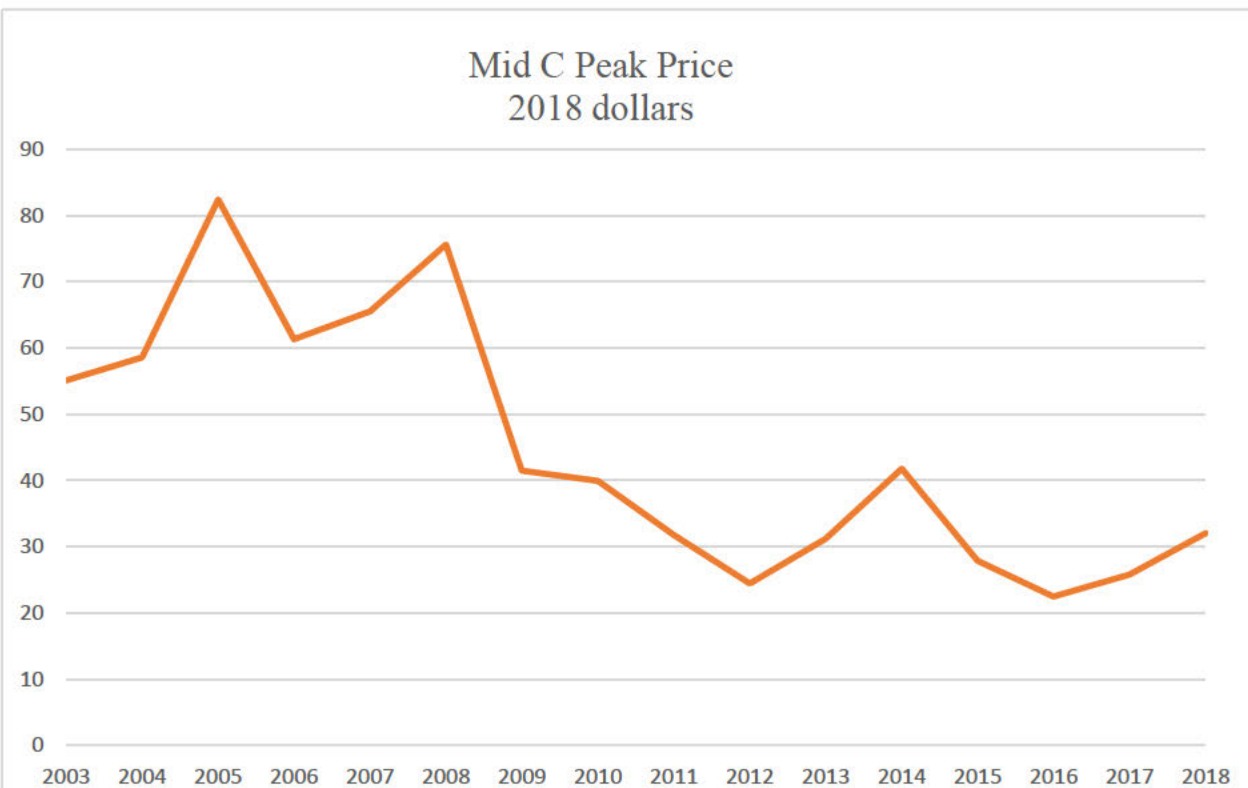
As the balancing authority and reliability provider within its service territory, PGE is charged with maintaining system balance and ensuring safe, reliable operation for all customers, regardless of supplier. PGE's operations personnel are responsible for planning generation over various timeframes and rely on a balancing authority area (BAA) level load forecast, inclusive of direct access loads, when planning the system. PGE must make sure it has sufficient capacity available if an ESS under-schedules its load in order to fulfill its reliability obligations. When an under-scheduling event occurs, PGE uses its resources (e.g. physical plants and contracts) to ensure the system is in load-resource balance and reliability is maintained while complying with all BAA responsibilities and requirements. Due to the nature of the interconnected grid, system supply and demand must always be matched in order to maintain frequency. This occurs every hour, regardless of ESS schedules, and PGE is the sole entity responsible for this balance within its BAA.

As evidenced in the below table, ESS under-scheduling for 2018 is positively correlated with PGE's highest hours of load, when the system is likely already constrained. PGE has not analyzed every under-scheduling event, nor has it attempted to quantify the costs of each event. However, during these events, PGE maintains system balance by having cost-of-service supply resources available and using them accordingly for the benefit of direct access loads.

Highest Load Hours	Percentage Under-scheduled
200	100.0%
400	95.0%
600	90.7%
800	87.5%
1000	85.2%
2000	75.7%
4000	65.5%
8000	55.3%
8760	52.4%

Annual Mid C Peak Price 2003-2018

	Nominal $	2018 $	
2003	40.37	55.09	
2004	44.07	58.58	
2005	64.10	82.42	
2006	49.22	61.31	
2007	54.09	65.51	
2008	64.85	75.63	
2009	35.45	41.49	
2010	34.67	39.92	
2011	28.46	31.77	
2012	22.34	24.43	
2013	28.91	31.16	
2014	39.37	41.76	
2015	26.28	27.84	
2016	21.46	22.45	
2017	25.19	25.78	
2018	32.02	32.02	
Average 2003-2008			*66.42*
Average 2013-2018			*30.16833333*



Constellation.
An Exelon Company

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AUG 28 2017
P.U.C.

August 25, 2017

VIA FEDEX

Public Utility Commission of Oregon
Attn: Commission Secretary, Ms. Kristi Collins
201 High St SE, Suite 100
Salem, OR 97301

Re: Constellation NewEnergy, Inc.'s Oregon Reconciliation Report

Dear Ms. Collins,

On behalf of Constellation NewEnergy, Inc. ("CNE") please accept this letter in compliance with CNE's obligation to submit its Reconciliation Report providing comparison of fuel mix and emissions associated with all of the seller's certificates, purchase or generation with the claimed fuel mix and emissions of all of the seller's products and sales pursuant to Or. Admin. R. § 860-038-0300. CNE does not make any claim other than unspecified market purchase mix; therefore, we have no responsive data to submit.

Please do not hesitate to contact us if you have any questions or concerns. My phone number is 312-681-1855 and my email address is amy.klaviter@constellation.com.

Sincerely,

Amy Klaviter
Analyst, Legal Compliance
On behalf of Constellation NewEnergy, Inc.

Constellation.
An Exelon Company

August 7, 2018

VIA FEDEX

Public Utility Commission of Oregon
Attn: Commission Secretary, Ms. Kristi Collins
201 High St SE, Suite 100
Salem, OR 97301

Re: Constellation NewEnergy, Inc.'s Oregon Reconciliation Report

Dear Ms. Collins,

On behalf of Constellation NewEnergy, Inc. ("CNE") please accept this letter in compliance with CNE's obligation to submit its Reconciliation Report providing comparison of fuel mix and emissions associated with all of the seller's certificates, purchase or generation with the claimed fuel mix and emissions of all of the seller's products and sales pursuant to Or. Admin. R. § 860-038-0300. CNE does not make any claim other than unspecified market purchase mix; therefore, we have no responsive data to submit.

Please do not hesitate to contact us if you have any questions or concerns. My phone number is 312-681-1855 and my email address is amy.klaviter@constellation.com.

Sincerely,

Amy Klaviter
Senior Analyst, Legal Compliance
On behalf of Constellation NewEnergy, Inc.