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June 13, 2023

Via Electronic Filing

Public Utility Commission of Oregon
201 High St SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket No. UE 416 – Redacted Opening Testimony of Bob Jenks and William Gehrke on Behalf of Oregon Citizens' Utility Board

To Whom It May Concern:

Please find enclosed the Opening Testimony and Exhibits of Bob Jenks (CUB/200-206) and William Gehrke (CUB/300-312) in Docket No. UE 416.

Please do not hesitate to contact me via email if you have any questions or need other materials.

Sincerely,

/s/ Michael Goetz
Michael Goetz, General Counsel
Oregon Citizens' Utility Board
610 SW Broadway, Ste. 400
Portland, OR 97205
E. mike@oregoncub.org

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 416

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision; and 2024 Annual Power Cost Update.	)
	)
	)

OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

June 13, 2023

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I. INTRODUCTION

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

A. My name is Bob Jenks. I am the Executive Director of the 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/201.

Q. What is the purpose of your testimony?

A. My testimony responds to various issues related to and proposals contained in Portland General Electric Company's (PGE or the Company) initial filing in this proceeding, as well as raising a proposal related to PGE's single-issue ratemaking mechanisms. My testimony discusses the following**:**

II. Business Risk and Shareholder Equity
III. PGE's Power Cost Adjustment Mechanism (PCAM)
IV. Single-Issue Ratemaking

V. Trackers for Request for Proposals (RFP) Independent Evaluator (IE) and Third-Party Consultants
VI. PGE's Proposal to Separate Deferrals and AAC
VII. PGE's Proposal Concerning Treatment of Energy Storage Resources

II. BUSINESS RISK AND SHAREHOLDER EQUITY

Q. What is the purpose of this section?

A. In this section, I discuss the role of shareholder equity, specifically as it relates to the risk profile that is generally assumed by utilities and their shareholders. In this proceeding, PGE discusses its perceived business risk at length and argues that various factors and mechanisms, including its PCAM, have increased its risk profile. According to the Company, the perceived increase in its risk profile justifies its request to increase its authorized return on equity (ROE). CUB disputes many of the Company's arguments. While our principal testimony responding to the Company's ROE increase request appears in AWEC-CUB/100, this testimony will address the Company's risk profile generally, and then specifically regarding its relation to the Company's proposed PCAM changes.

Q. Please describe what you mean by business risk.

A. Regulated utilities are for-profit monopolies. This is unusual. Generally, for-profit businesses operate in competitive markets. Businesses in these markets cannot charge too much for their product or customers will purchase from alternative suppliers. But with utilities, customers are captive. They cannot turn to an alternative. Instead, customers rely on regulation to substitute for market discipline.

In order to protect their shareholders, utilities like PGE seek to claim that any risk that is not under its control should fall on customers, but this is misguided. This suggests that the utility should get to recover all of its costs with the only exception being prudence disallowances, which are rare. Essentially, this theory seeks a regulatory paradigm where utility investors are making largely risk-free investments. However, the Public Utility Commission of Oregon (Commission) has held in a variety of settings that some level of business risk should be borne by shareholders, or at least appropriately balanced between shareholders and customers. The Commission's continued approval of PGE's current PCAM is just one example of a means to fairly balance risk between the Company and its customers.

The PCAM is a form of retroactive ratemaking, meaning that it enables costs or benefits that have accrued in the past to be passed onto customers. According to PGE, the PCAM should guarantee that PGE recover all of its prudently incurred costs. However, this is not how regulated utilities are supposed to operate. Shareholders of utilities are not supposed to be making risk-free investments. Retroactive adjustments are not supposed to be used to eliminate normal business risk. Instead, shareholders are given returns on equity that fairly compensate them for the business risk that they take on. The Commission must allow regulated utilities the *opportunity* to earn a reasonable rate of return, but the Commission cannot ensure that utilities will earn a reasonable rate of return.[1] In order to justify the higher ROE that utilities generally seek, their shareholders must assume some level of risk that they will not recover all of their costs.

Regulated utilities seem to be troubled by the idea that we use forward-looking rate cases to set prices which are designed to cover costs and provide a reasonable return, but that the utility generally takes the risk of higher costs or lower demand than was anticipated in the test year. However, this well-established regulatory paradigm mirrors the nature of for-profit businesses operating in a market. For-profit businesses are subject to business risk. Businesses routinely set prices while being subject to the risk that costs will be higher than expected, or sales will be lower than expected. Their ability to change prices to offset increased costs can be restrained by the competitive market.

The purpose of regulation is to set just and reasonable rates and protect customers from the abuses that would naturally come from for-profit monopoly service. It is not to eliminate the normal business risk for investors. Under this established regulatory framework, customers also assume a risk that the utility's cost of service will be below what is forecasted in the test year, which enables the utility to retain benefits.

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[1] Charles Davis, Or. Op. Atty. Gen., OP-6076 (1987) at 11 ("Regulators must allow regulated utilities an opportunity to earn a reasonable rate of return. Regulators cannot ensure that utilities will earn a reasonable rate of return.").

Q. How is business risk related to equity?

A. Business risk is directly tied to equity. The Company's ROE, or profit margin, compensates investors for the business risk associated with a capital investment. Businesses that are subject to higher risk would normally require a higher ROE to attract investment capital. But utilities think they are different. It is not unusual for a regulated utility to seek what PGE is seeking in this case: higher ROE to increase compensation to investors combined with lower risk by shifting risk to customers.

However, equity is tied directly to risk, and a lower risk profile generally suggests that a lower ROE is warranted. Utilities typically finance capital investments with a combination of equity and debt. Debt is cheaper, but the addition of equity allows the utility to absorb risk. For example, if a utility's service territory experiences unusually mild weather it may not collect enough revenue to cover all of the costs associated with financing its capital investments. If the utility failed to pay its debt, the holder of that debt can sue and demand that the debt and interest on the debt be paid. However, unlike debt which must be paid, dividends to shareholders can be reduced. In this manner, equity acts as a shock absorber, absorbing business risk. Weather-related variations in volumetric sales are a risk that Oregon-regulated utilities have generally assumed, and utilities are able to use equity to help absorb this risk.

When utilities ask to completely eliminate business risk, they are asking that equity no longer be used to absorb business risk. But, in this circumstance, there is no longer a benefit of equity. Instead, we should finance utility investments entirely through debt. This would lower the cost of financing capital projects to customers and would be appropriate because, under this scenario, business risk would be completely eliminated.

This represents much of the difference between publicly owned utilities and for-profit utilities. Public power has lower financing costs but does not have equity investment to absorb risk. Customers of public power utilities must absorb more risk by having greater volatility to rates or by pre-funding a reserve which can absorb risk.

We can also see the impact of equity when we compare gas and electric utilities. Electric utilities have more rate-based capital (more equity), have a higher business risk associated with power supply, and typically earn a higher ROE in exchange. Because they have significantly more equity investment since they are vertically integrated, they have a higher risk tolerance than gas utilities. Gas utilities generally do not have equity investment in gas supply – only in the distribution network – and therefore have a lower risk tolerance and a lower ROE.

The role of business risk and the Company's request to increase its ROE in this case are intertwined with many issues PGE raises. Perhaps the largest example is its proposal to completely shift nearly all risk associated with its power cost forecasting to customers while simultaneously seeking a higher ROE.

III. PCAM

Q. What is the purpose of this section of your testimony?

A. I will explain the history of the PCAM, why CUB opposes PGE's proposed changes to the mechanism, and explain CUB's proposal to modify the PCAM. CUB proposes the following structure for PGE's PCAM going forward:

Earnings Test: The earning test, based on a range of reasonable earnings (100 basis points ± authorized earnings) should not change. This is an important customer protection while ensuring that the mechanism allows the Company to earn a return within a reasonable range. We should not be changing from forecasted prices when earnings are reasonable.

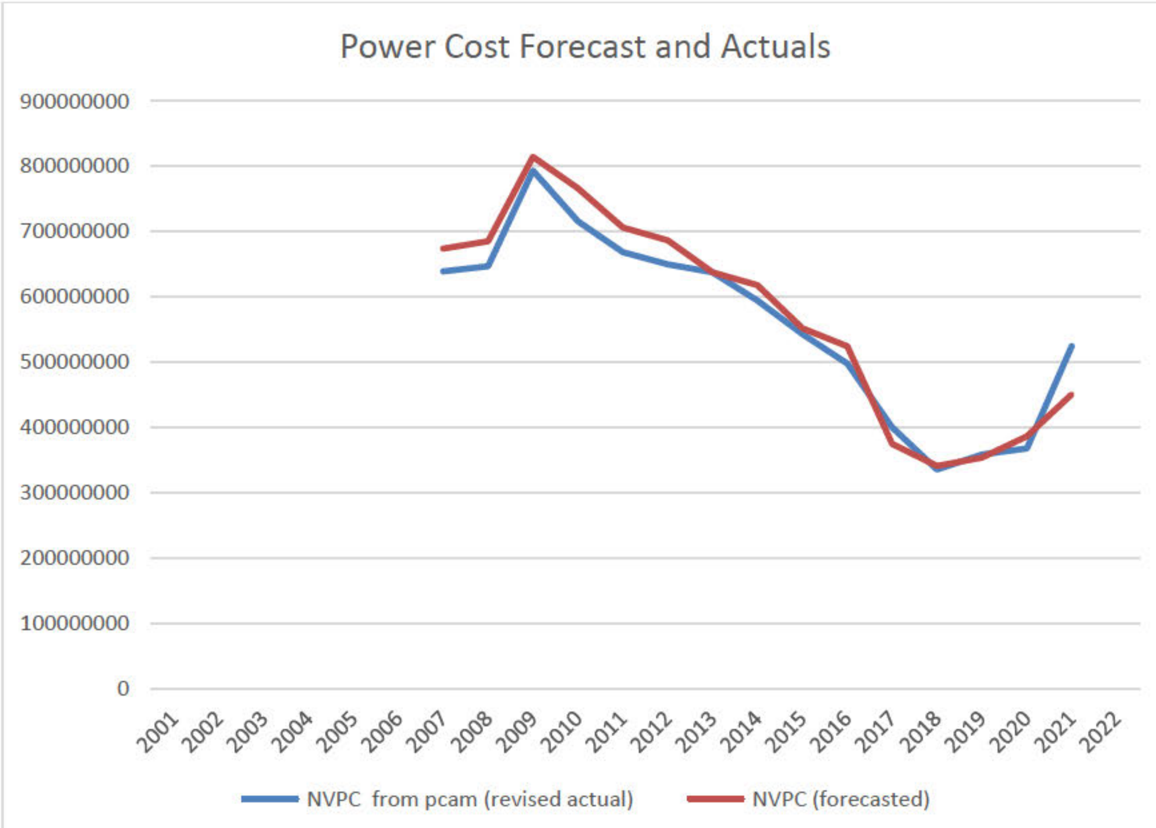
Dead band**:** The Commission stated in a number of proceedings that the dead band should be based on the amount of equity that a Company has, but as PGE has dramatically increased its equity over the years, there has been no adjustment to the dead band. CUB believes we should return to a dead band based on basis points ROE. The current dead band has shrunk from 150/75 basis points to approximately 50/25 basis points. CUB proposes splitting the difference by setting a dead band of 100/50 basis points.

Sharing: CUB proposes to retain the current sharing percentages at 90/10.

Q. What is CUB's view of PGE's proposal to change the PCAM?

A. CUB strongly opposes PGE's proposed changes. PGE is proposing to shift the business risk associated with power cost forecasting to customers. Despite PGE's arguments to the contrary, there is no evidence that there is a problem with PGE's PCAM, and it has been operating as the Commission intended since its inception. The variation between forecasted and actual power costs is normally small and falls within the deadband, resulting in no rate change. It is only in unusual circumstances that there is a variation that is large enough to lead to a surcharge or refund. Figure 1 below shows the variation between forecasted and actual power costs since the inception of PGE's current PCAM.

Figure 1[2]



PGE argues that current circumstances are different than they were in 2006 when the PCAM began, that markets are—and will continue to be—volatile, and that the continued addition of renewable resources increases PGE risk. PGE offers little evidence to support its arguments and its proposal is inconsistent with the history of power cost recovery in Oregon.

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[2] UE 416 – CUB/202.

A. *Background on the Current PCAM*

Q. Can you discuss the history of power cost recovery?

A. Yes. PGE identifies 2007 as representative of the time period when the PCAM was "originally developed and implemented."[3] While a version of the current PCAM (one with a wider deadband) was approved in 2007, the methodology of the PCAM and the Commission's power cost recovery principles date back to the Western Power Crisis in 2001. The PCAM methodology was developed, considered, and adjusted through a series of Commission dockets. Through these proceedings, the Commission has been consistent in its recognition that PCAM principles are in place to allow for rate changes only in unusual circumstances, that equity investors should carry traditional business risk, and that customers should be protected from volatility in rates. This is not a one-off policy that was decided in a single case, but is a well-crafted policy that has been in place for decades and reiterated by the Commission in multiple dockets:

UM 995
UM 1008/1009
UE 115
UE165
UE 180/181/184
UE 215
UE 246
UE 283
UM 1662

The modern history that led to the current PCAM began in 2001 during the Western Power Crisis. At the time, there were no annual power cost mechanisms—no mechanism to annually forecast power costs and no mechanism

[3] UE 416 – PGE/400/Sims – Outama/2.

to annually true-up power costs. But the failures that led to the Western Power Crisis associated with poor market design and market manipulation, combined with low hydro conditions, and an unplanned outage of a coal plant led to a set of deferrals to capture power cost excursions. The Commission recognized the extreme volatility of the market, but wanted to protect customers from that volatility by establishing a mechanism that focused on costs that were beyond the normal risk that the utilities undertook. The following dockets and events led to the PCAM in the form it exists in today.

UM 995 – PacifiCorp Power Cost Deferral.

UM 995 was a deferral filed by PacifiCorp for excess power costs caused by the Western Power Crisis, low hydro conditions, and a forced outage at the Hunter coal plant. PacifiCorp incurred approximately $786.7 million in excess net power costs on a total company basis during the deferral period.[4] The Commission implemented a mechanism that shared excess power costs that were outside of a dead band:

> ***Dead band***: A dead band was established for power cost changes equivalent to +/- 250 basis points return on equity around the baseline (a band in which the utility bears all the cost and receives all the benefit.);[5]
>
> ***Sharing bands***: a 50/50 sharing band for power cost changes equivalent to between 250 and 400 basis points;
>
> a 75/25 sharing band for power cost changes equivalent to more than 400 basis points, in which customers bear 75 percent and the company bears 25 percent.[6]

[4] OPUC Order No. 02-469 at 3
[5] OPUC Order No. 01-420.
[6] OPUC Order No. 01-420 at 5.

UM 1008 and 1009 -- PGE Power Cost Deferral.

PGE also had a power cost deferral during the Western Energy Crisis due to volatile wholesale energy prices combined with a low water year. Both PGE and Commission Staff initiated power cost deferrals for PGE. These two filings were consolidated as UM 1008/UM 1009. This case was settled with a stipulation between Staff, PGE, CUB, ICNU, and Fred Meyer Stores. This agreement was adopted by the Commission and largely followed the UM 995 decision except that it assigned 90% of costs that were more than 400 basis points above the baseline to customers:[7]

Dead band: A dead band of +/- 35 million was established around the baseline forecast of net variable power costs. This was equivalent to approximately 250 basis points ROE. Within this dead band the utility bears all the cost and receives all the benefit;[8]

Sharing bands: a 50/50 sharing band for power cost changes between $35 million and $56 million above or below the baseline (equivalent to between 250 and 400 basis points);

a 90/10 sharing band for power cost changes equivalent to more than 400 basis points, in which customers bear 90 percent and the company bears 10 percent.

Commission Staff believed that one reason a wide dead band was necessary was the volatile wholesale market:[9]

> Staff believes the width of the dead band (equivalent to 250 basis points return on equity) and sharing between customers and the company is reasonable for several reasons. First, utilities typically bear the risk for cost changes in normal operating expenses between rate cases. The potential magnitude of power cost changes is the result of a highly volatile wholesale market, which justifies not only deferral of a portion of the variance but also a sharing between customers and the company (until a subsequent general

[7] OPUC Order No. 01-231 at 10-11.
[8] OPUC Order No. 01-420.
[9] OPUC Order No. 01-231 at 5. In contrast, in this proceeding, PGE asserts that market volatility now warrants completely eliminating the PCAM dead bands.

rate change) in such extraordinary circumstances.

UE 115 – Western Power Crisis General Rate Case.

UE 115 was the big general rate case that PGE filed during the power crisis. There were a lot of issues in that docket, including implementing SB 1149, the Oregon Electric Restructuring Law. UE 115 established an annual power cost forecast that was later renamed to the AUT. In UE 115, the parties agreed to a power cost adjustment to track the Power Cost Variance (PCV) between actual Net Variable Power Costs (NVPC) and forecasted NVPC:[10]

Dead Band: A dead band of $28 million was established. This was approximately 200 basis points.

Sharing Bands: A 50/50 sharing band was established for costs that varied from the baseline between $28 million and $38 million;

A 85% sharing band was established for costs that varied from the baseline between $38 million and $100 million;

A 90% sharing band was established for costs that varied from the baseline between $100 million and $200 million;

A 95% sharing band was established for costs that varied from the baseline in excess of $200 million.

In approving the power cost stipulation, the Commission noted that "PGE's power cost situation is unique, given PGE's exposure to the wholesale energy market and the current uncertainty and volatility of that market."[11] During perhaps the most volatile market period in recent utility history, the Commission found that PCAM dead bands were appropriate. This greatly undercuts PGE's position in this proceeding.

UE165 – Hydro-Only PCAM.

[10] OPUC Order No. 01-777, Appendix D, page 19 of 28.
[11] OPUC Order No. 01-777 at 20.

PGE proposed a hydro-specific PCAM in 2004. The proposed mechanism was intended to dampen the fluctuations in PGE's annual power costs that were caused by variations in hydro conditions. PGE described a number of reasons why it believed it was uniquely suited for such a mechanism—roughly 10 percent of that company's generation portfolio is company-owned hydro, which is an inherently unpredictable resource that has significant swings in annual generation due to fluctuating water levels. The Commission rejected PGE's proposed PCAM and established a set of design criteria that would be used to evaluate PCAM proposals going forward, which are still in effect today:[12]

Design Criteria for PCAMs

> First, a PCAM should only be triggered by extreme and unusual events.
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> Second, adjustments should not be made if earnings are already reasonable.
>
> Third, the mechanism should remain revenue neutral over time.
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> Fourth, in order to ensure that the three prior criteria are effective, the mechanism must be intended to remain in place on a long-term basis.

UE 180/181/184 – Original version of current PCAM.

UE 180/181/184 was the docket where the current PCAM was adopted in its original form. PGE proposed a PCAM that allocated 90% of any variance in power costs to customers.[13] PGE argued "vigorously against the imposition of a deadband," claiming that other states rarely require dead bands or sharing mechanisms and including one "would result in Oregon being seen as a negative

[12] OPUC Order No 05-1261 at 8-10.
[13] OPUC Order No. 07-015.

regulatory environment, leading to a possible downgrade in PGE's credit rating."[14] In addition, PGE argued that a dead band would not be sustainable and that power costs represented so much of the Company's costs that it could not absorb negative variations.[15]

The Commission rejected PGE's arguments and reiterated the design criteria it had proposed in UE 165 – "it must be limited to unusual events, there will be no adjustments if overall earnings are reasonable, it must be revenue neutral, and it must operate in the long-term."[16] The Commission adopted a PCAM with the following design elements:

Earnings Test: The Commission established an earnings deadband of <u>+</u> 100 basis points around the company's allowed ROE. Within this band earnings are considered reasonable and there would not be refunds or surcharges associated with the PCAM. The Commission cited two reasons for this earnings deadband rather setting an earnings test at allowed ROE. First, it noted that there is a range of acceptable returns on equity. Second, it recognized that an earnings test does not examine a utility's costs as "thoroughly" as a full rate case.

Dead band: The Commission established an asymmetric dead band ranging from 75 basis points ROE below forecasted power costs, to 150 basis points ROE above forecasted power costs. The Commission said that the dead band needed to be asymmetric to be revenue neutral and that "the ability to absorb power cost increases depends on a utility's total rate base."[17] The Commission held that this structure enabled PGE to "capture power cost variations that exceed those considered part of normal business risk."[18]

Sharing: The Commission decided that 90% of any power costs that were outside of the dead band and passed the earnings test would fall on customers in order to give PGE an incentive to manage its costs.

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[14] *Id.*
[15] *Id.*
[16] *Id.*
[17] *Id.*
[18] *Id.*

Amortization limit: The Commission limited amortization of deferred amounts under the PCAM to 6% of revenues for the preceding calendar year.

UE 215 – Modification of the PCAM.

In UE 215, PGE proposed changing the dead band which the Commission had established as a range of 75 basis points ROE below the forecasted net power costs to 150 basis points ROE above the forecasted net power costs. Instead, PGE proposed a deadband of $10 million either above or below the forecast. In addition, PGE proposed changing the earnings test to be set at the ROE established in the last rate case with no earnings dead band. PGE argued that the existing PCAM did not allow recovery of all prudently incurred power costs and was not consistent with other PCAMs around the country.[19]

The Commission adopted a stipulation in the case that adjusted the dead band to $15 million below the forecasted power costs to $30 million above the forecasted power costs. In adopting the stipulation, the Commission again cited to and upheld the design criteria it had discussed in Orders 07-015 and 05-1261.[20]

UE 246 – PacifiCorp's PCAM.

In UE 246, PacifiCorp asked for a PCAM with dollar-for-dollar recovery for all power costs citing the impacts of Oregon Renewable Portfolio Standard (RPS). PacifiCorp claimed its under-recovery of NPC in Oregon rates was due primarily to the inability to accurately forecast wind generation and factors associated with integrating a new, large fleet of renewable resources whose generation fluctuates

[19] OPUC Order No. 10-478.
[20] OPUC Order No. 10-478.

widely. Because the RPS allows the Company to recover all prudently incurred RPS compliance costs—including the variable NPC impacts associated with integrating renewable energy sources—PacifiCorp argued it was entitled to dollar-for-dollar recovery of all power costs without dead bands, earning bands, sharing percentages, or any other feature that it perceived would deprive it of dollar-for-dollar recovery of any under-recovery of NPC.

The Commission rejected PacifiCorp's proposal and reiterated the design criteria that it applied to PCAMs in the cases cited above. The Commission adopted a PCAM similar to PGE's:[21]

Earnings Test. The Commission established an earnings dead band of ± 100 basis points around the company's allowed ROE.

Dead band. The Commission adopted the same asymmetric dead band that it had for PGE: $15 million below forecasted power costs to $30 million above forecasted power costs. The Commission also stated that the dead band was based on "Pacific Power's authorized rate base, rather than net power costs. In determining an appropriate power cost dead band, we look to the size of the utility's rate base and to the utility's authorized ROE.[22]"

Sharing: The Commission decided that 90% of any power costs that were outside of the dead band and passed the earnings test would fall on customers in order to give PacifiCorp an incentive to manage its costs.

Amortization limit: The Commission limited amortization of deferred amounts under the PCAM to 6% of revenues for the preceding calendar year.

UE 283 – Renewable Carve Out.

In UE 283, PGE proposed a PCAM carve-out for any cost that it could associate with renewables, claiming that this is required by SB 838's provision allowing

[21] OPUC Order No. 12-493.
[22] OPUC Order No. 12-493.

recovery of prudently incurred costs associated with the Renewable Portfolio Standard. PGE, like PacifiCorp in UE 246, argued that SB 838 required dollar-for-dollar recovery. No other party supported PGE's position, and the Commission approved a stipulation with no changes to the PCAM.[23]

UM 1662 – PAC and PGE Renewable Resource Tracking Mechanism.

In 2015, PGE and PacifiCorp jointly proposed changing the PCAM to allow for dollar-for-dollar recovery of costs, including variable power costs that they claimed were related to the RPS. The Commission found that SB 838 "does not mandate dollar-for-dollar recovery of all RPS costs, but rather allows the utilities the opportunity to recover their variable costs."[24] The Commission rejected the idea that variable power costs associated with the RPS warrant a change in ratemaking treatment of power costs. The Commission rejected the Companies' proposal, closed the docket and retained the current PCAMs, finding that the current PCAM structure gave the utilities the opportunity to recover their variable costs.[25]

Q. What conclusions does CUB draw from this history?

A. Oregon's regulatory approach to variable power costs has been consistent for more than 20 years. Costs are forecasted. Retroactive ratemaking is only allowed in unusual circumstances and when earnings deviate from reasonable levels. Dead bands, sharing, and an earnings test are consistent design elements, and these elements, taken together, ensure that the utilities are earning within a range

[23] OPUC Order No. 14-422.
[24] OPUC Order No 15-408 at 6.
[25] OPUC Order No 15-408 page 7 and 8.

of reasonableness while fairly balancing customer and shareholder interests. Utilities have consistently argued that they should be allowed to retroactively recover all prudently incurred costs without being subject to normal business risk. Utilities have consistently argued that other states do things differently. But the Commission has been consistent in rejecting these arguments, and CUB urges it to do so here as well.

In addition, it should be noted that some of arguments that PGE has made over the years have turned out be false. The PCAM did not lead to a credit downgrade for PGE. The dead band has not been unsustainable. Instead, it has operated as intended for many years and continues to fairly balance cost and risk between the utilities and their customers.

B. *Responding to PGE's Arguments*

Q. Why is PGE requesting a change to the PCAM at this time?

A. It is not entirely clear. Many of their arguments are reiterated from prior testimony and have been rejected in the past. Things like:

- Rating agencies prefer less shareholder risk;
- The current mechanism does not ensure full recovery of prudently incurred costs; and
- Oregon's mechanism is different than other states.

Most of their new arguments relate to climate change, renewable resources, and market risk. These arguments don't hold up to scrutiny.

One new argument raised by PGE that is unrelated to climate change is that the current mechanism creates a poor incentive for parties that are participating in the

AUT – customer groups favor lower power cost forecasts and investors favor higher forecasts. Of course, this is an argument against using forecasts for setting rates, generally. But the problem with this argument is that the AUT (and RVM, which predated the AUT) are pretty accurate. In the early days of the PCAM, PGE's power cost forecasts were generally higher than actual power costs but were still normally in the dead band.

In recent years, NVPC forecasts in the AUT have been extremely accurate. It is only in the last year or so—post-COVID, with supply chain problems and the war in Ukraine upsetting energy markets—that we have seen a significant deviation where the forecast was low. This shows that the PCAM is not skewing the forecasting of power costs. More importantly, this shows that the PCAM is serving its purpose. It is there to allocate the costs of unusual events. And the post-COVID environment we just went through is certainly unusual.[26] CUB's Figure 1 below, which was used above as well, demonstrates this.

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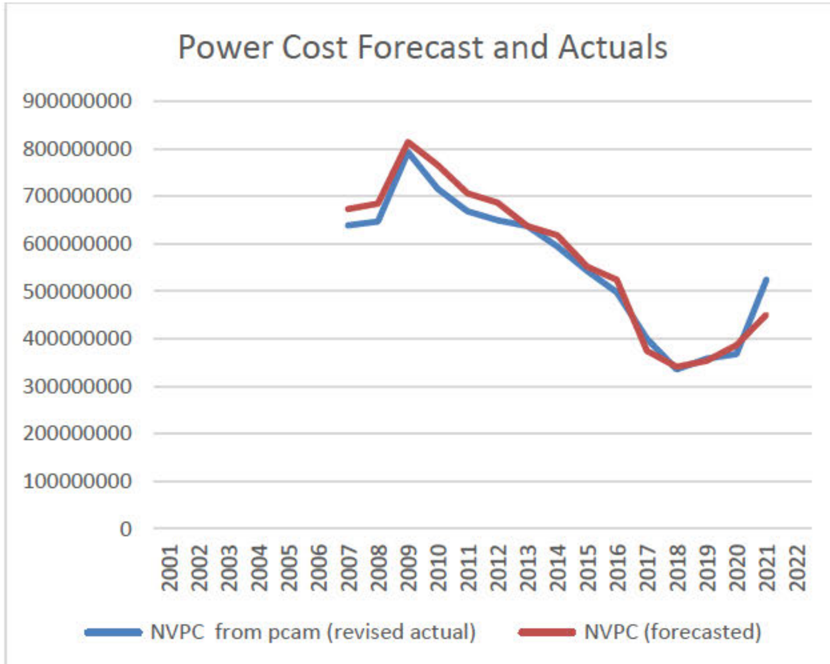
[26] UE 416 – CUB/202.



Q. What about PGE's arguments about climate change, changing resources, and volatile markets?

A. Most of these arguments do not stand up to evidence. On the issue of resource mix, the Company argues:

> Hydro and dispatchable natural gas-fired and coal thermal generation composed nearly the entirety of PGE's resource portfolio with only a small amount of contracted renewable resources in the portfolio in 2005 and 2006.[27]

Unfortunately, this statement is a little bit misleading. It is important to recognize that PGE was owned by Enron from 1997 to 2006 and as such PGE was a proponent of deregulation of electric utilities, including divesting the generation from the distribution utility. And, as a distribution utility, PGE stopped investing in generation at this time. PGE brought a gas plant, Coyote Springs, onto its system in 1994 and did not bring on a new large generating unit until 2007.

[27] *See* UE 416 - PGE / 400 Sims – Outama/10.

When the PCAM policies were being developed between 2001 and 2007, PGE's largest resource was market purchases.

Figure 2 is from the Commission's Utility Statistics Book from 2006. In 2006, PGE had a total of 7 million MWh of its own generation, but its net purchased power was 26 million MWh. This can be contrasted with PacifiCorp. While PGE's net purchases were 3.5 times its production, PacifiCorp was purchasing less than one third of its production. PGE was very exposed to the market, which was not a surprise since this was the end of Enron's ownership, and Enron favored market purchases over utility-owned generation. Market purchases do create a net power cost risk, which is captured in the design of the current PCAM. Even so, PGE's exposure to the market has gone down since Enron ownership ended and PGE began investing in generating resources. PGE's exposure to the market peaked in 2006, the year that they were sold out of Enron's bankruptcy and began building resources again.[28] Figure 3 demonstrates this.

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[28] UE 416 – CUB/202.

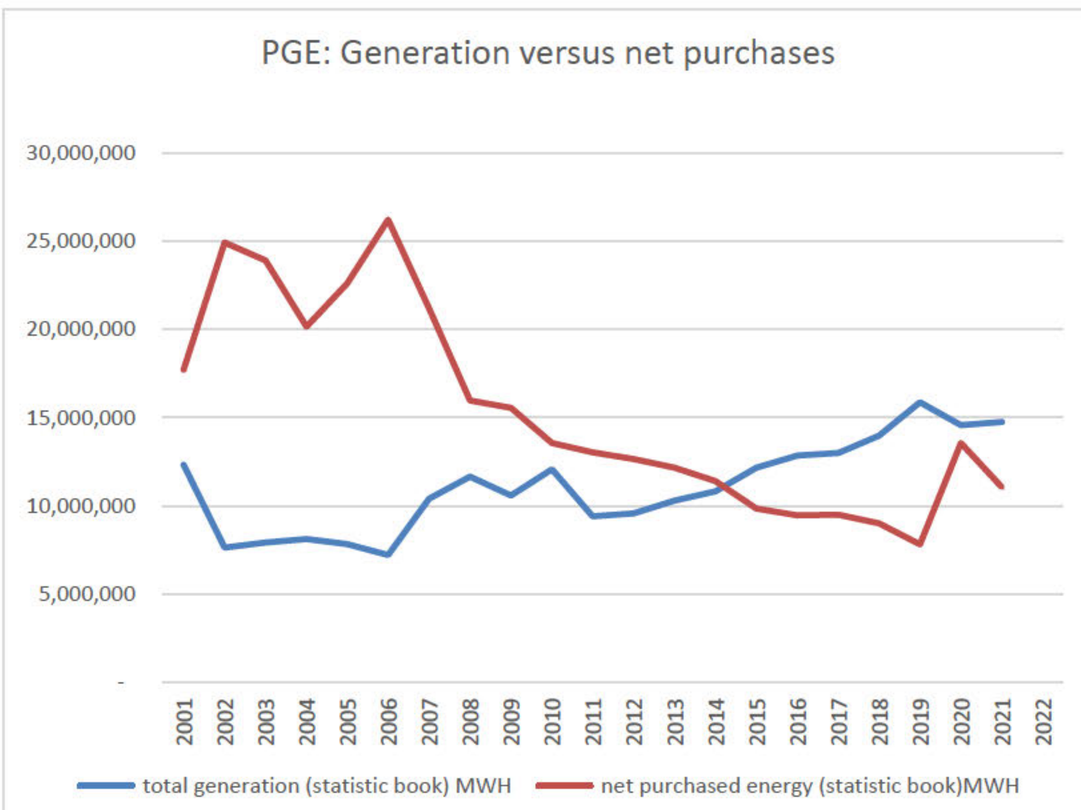
Figure 3 below shows PGE's historic portfolio of generation assets versus market purchases.

Figure 2

Investor-Owned Electric Utilities in Oregon
SOURCE AND DISPOSITION OF ELECTRIC ENERGY
OREGON AND SYSTEM (MWh)[A]
Year Ending December 31, 2006

	Idaho Power Co.		PacifiCorp		Portland General Electric Co.
	Oregon	System	Oregon	System	Oregon
GENERATION (MWh)					
Steam	241,557	6,948,258	0	45,490,947	3,634,834
Nuclear	0	0	(25)	(25)	0
Hydro	3,786,253	9,206,526	1,645,652	4,620,883	2,001,752
Other	0	72,859	1,611,233	3,554,726	1,572,308
Total Generation	4,027,810	16,227,643	3,256,860	53,666,531	7,208,894
PURCHASED ENERGY	(B)	4,964,024	3,667,273	15,918,949	26,224,528
INTERCHANGES – NET	(B)	(177,172)	12,423,361	363,441	(14,791)
Grand Total Available	(B)	21,014,495	19,347,494	69,948,921	33,418,631

Figure 3



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Q. PGE argues that the resources it built were non-baseload and therefore riskier. Does evidence support this conclusion?

A. No. Again, the evidence does not support this. It is important to recognize that renewable resources generate power without any fuel cost and fuel cost is a component of net power costs. After the RPS passed in 2007, PGE began adding renewable resources, but these resources displaced some of the large volume of market purchases PGE was making without adding fuel costs. PGE was able to replace market exposure with ratebased generating resources that had no fuel costs. In effect, PGE was able to replace NVPC with ratebased renewables. This increased ratebase significantly, while simultaneously reducing the Company's exposure NVPC. PGE's ratebase has increased from around 3.5 billion in 2001 to approximately $12 billion today, while its NVPC have declined from around 50% of their costs to less than 30%.[29] Therefore, PGE is significantly less exposed to the market than when the PCAM was initially designed and simultaneously PGE's risk tolerance has increased significantly because its equity has significantly grown through ratebase additions. Figures 4 and 5 demonstrate this.

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[29] UE 416 – CUB/202.

Figure 4[30]

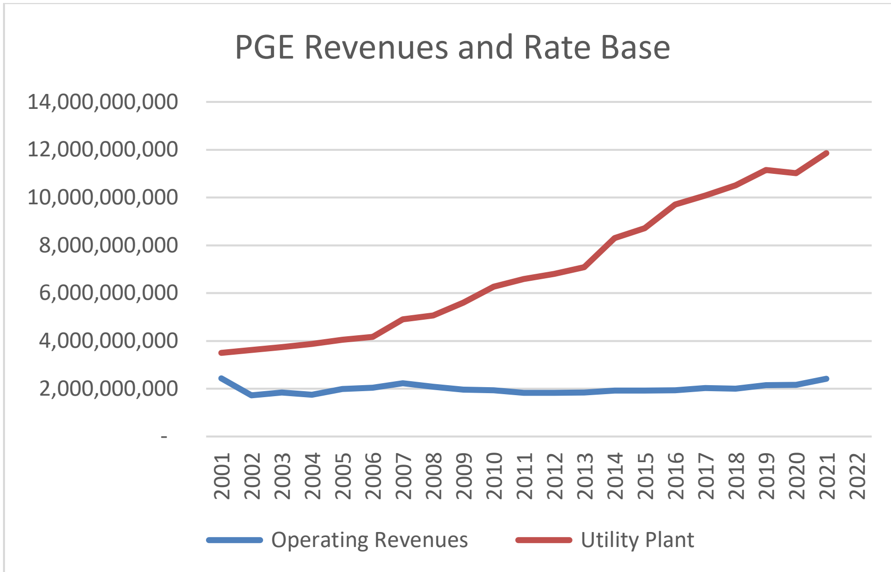
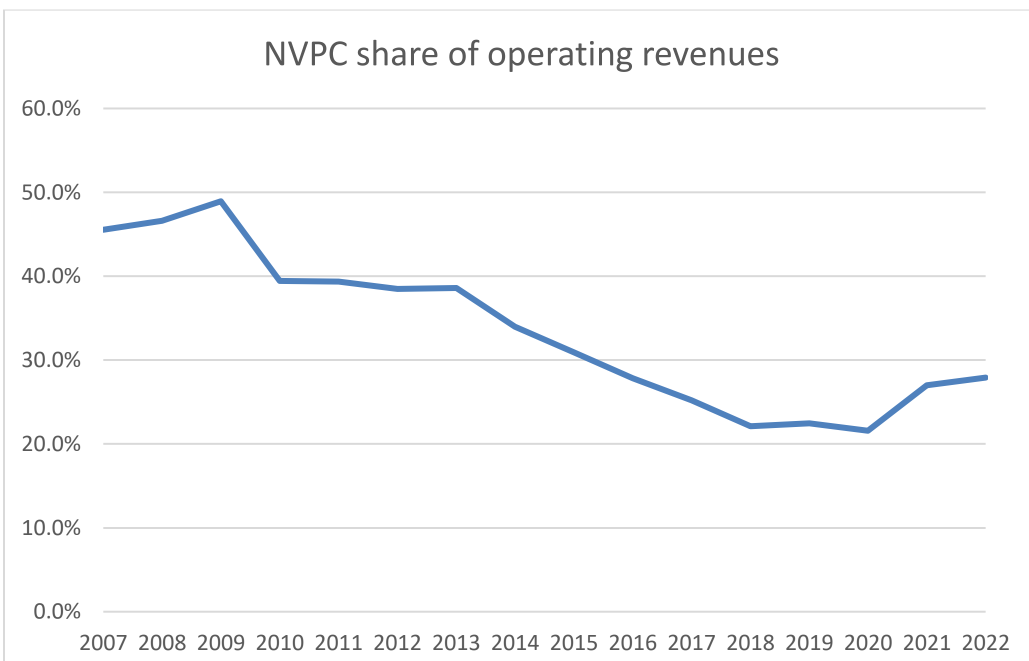


Figure 5[31]



[30] UE 416 – CUB/202.
[31] UE 416 – CUB/202.

PGE is now in the process of a similar change to its capacity resources. Rather than relying on gas-fired peakers, the Company is investing in battery storage. It is replacing a variable power cost (natural gas as fuel) with a fixed cost asset that does not require fuel. In addition, it is important to remember that the risk tolerance of a utility is related to the total level of equity that it has. Renewable resources and battery storage, when owned by a utility, require significant rate base investments – significant equity – and increase the risk tolerance of the Company. If PGE must absorb $10 million within the dead band, it is a much smaller hit today with a rate base of $12 billion than it did when there was only $4 million in rate base. PGE's arguments around eliminating the dead bands make little sense when viewed through this lens—the lens that the Commission has historically viewed the PCAM through.

Q. PGE argues that climate change has increased the risk of extreme events, and this should require changes in the PCAM. How do you respond?

A. PGE argues that severe weather and load events are driving extreme volatility, beyond the notion of normal business risk from when the PCAM was originally implemented. But this is not the case.

The original PCAM was established in 2007 and the dead band was set to absorb the normal business risk. The first of the Commission design principles was:

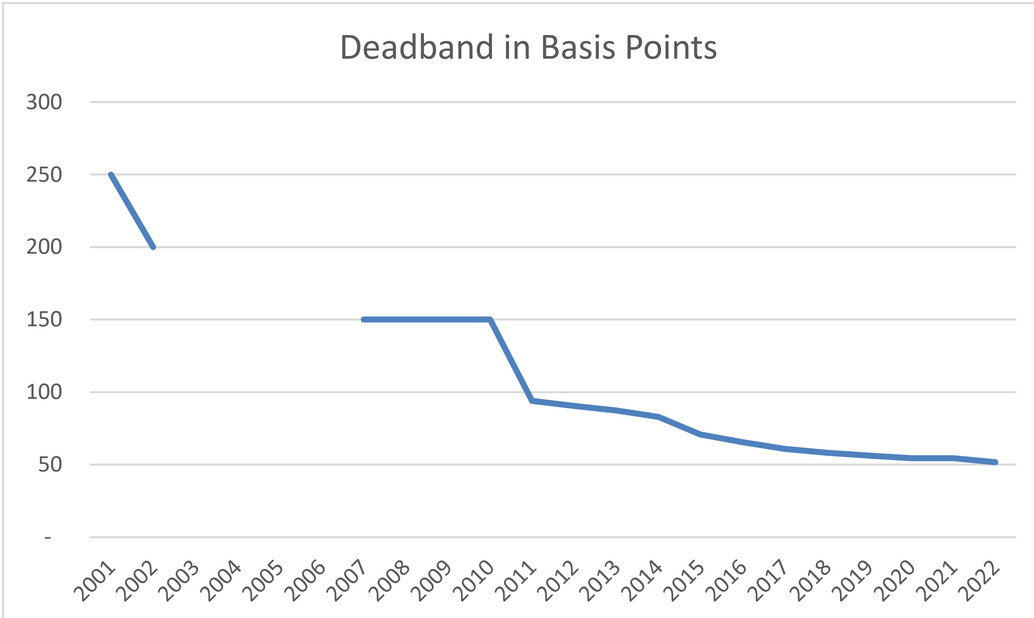
> The PCAM's application should be limited to unusual events and capture power cost variances that exceed those considered normal business risk.[32]

Costs outside the dead band represented unusual events and unusual risk beyond normal business risk. As our Figure 1 shows, the PCAM has generally been within the dead band which means that the PCAM has normally operated under conditions that reflect normal business risk. But to the degree cost related to extreme events can create risk beyond the normal business risk, that is the fundamental purpose of the PCAM – allow recovery of costs from unusual events that are outside of normal business risk. PGE's argument seems to be that because there may be costs that are outside of normal business risk, the Commission should allocate normal business risk to customers. This directly contradicts the original PCAM principles.

But it is also important to recognize that the normal business risk that the utility is expected to absorb has declined. The Commission has repeatedly held that the dead band reflects normal business risk, and it should be sized based on the utility's ratebase. PGE's dead band – the amount of business risk allocated to shareholders – has declined by 5-fold over the last 20 years due to the overall grown of its ratebase.[33] Figure 6 demonstrates this.

[32] Commission design principle articulated in multiple cases mentioned in our review of PCAM history.
[33] UE 416 – CUB Exhibit 202. PGE did not have a PCAM or power cost deferral from 2003 to 2007.

Figure 6



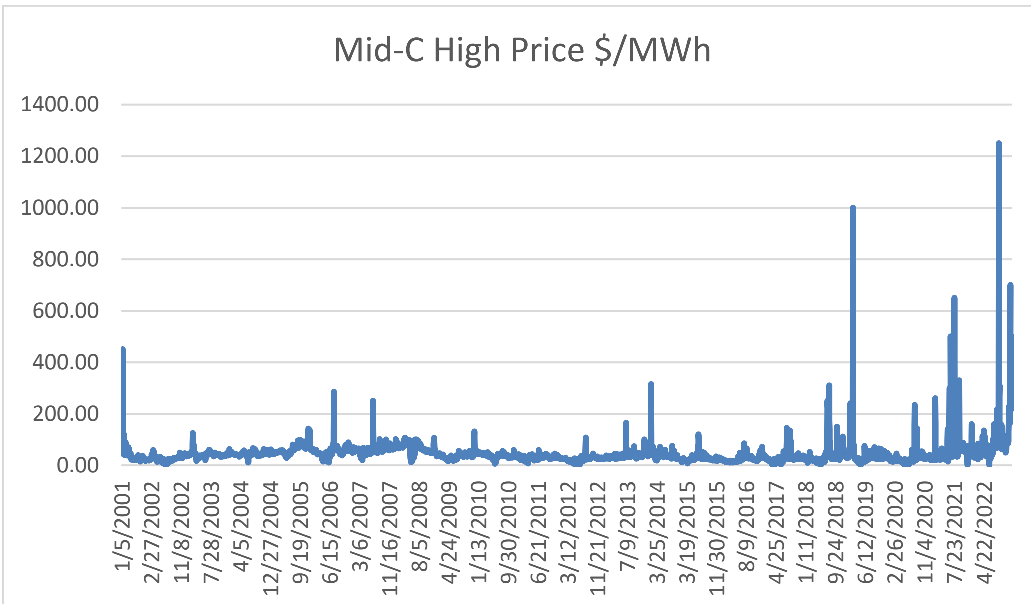
In addition, while PGE argues that extreme volatility is new and changes its risk profile, this mechanism was first developed during the Western Power Crisis in 2001, when wholesale gas and electric prices were highly volatile. At that time, an argument in favor of a 250-basis point deadband was to protect customers from the volatility of the market. Today, PGE is arguing that the volatility of the market should be redirected towards customers. This makes little sense.

Figure 7 below shows the high prices at Mid-C.[34] The raw data from this comes from the Energy Information Administration. There are two important things to note about this graph:

[34] Source of data: https://www.eia.gov/electricity/wholesale/#history.

- It has not been adjusted for inflation. Adjusting a $500 price in 2001 by the Consumer Price Index creates a new price of $900 in today's dollars.
- PGE was more exposed to the market in the early 2000's. In 2002 and 2003, PGE's net power purchases were 3 times larger than its generation.

Figure 7



Q. What is your view of PGE's argument that changes to the PCAM are necessary due to resource adequacy requirements, the EIM, and potential new market structures?

A. CUB disagrees. There are several changes that have been incorporated or proposed for markets and resource adequacy, but these should lower PGE's NVPC risk, not increase it. PGE has argued that, as the Control Area Operator, it has to procure resources to ensure reliability for direct access customers. Resource adequacy requirements are changing this dynamic, which reduces PGE's costs and risks. The EIM and other market reforms are designed to create more efficiency and lower NVPC. These are reforms that are reducing the market risk that PGE is exposed to.

Q. What is your view of the new principles PGE proposes to be used to evaluate PCAMs?

A. They should be rejected. As our overview of the history of PCAMs has demonstrated, the Commission has reiterated the principles in multiple cases over many years. They are sound and have served Oregon well.

When viewed critically, it is obvious that PGE's principles are self-serving.

- PGE takes the principle that a PCAM adjustment should be reserved for unusual circumstances and seeks to completely change it to allow the utility to be able to fully recover its prudently incurred costs.[35] Remember that this is a retroactive mechanism. Current ratemaking allows the utility to fully recover its prudently incurred costs on a forecasted basis. The question here is how to allocate the risk that those forecasts are incorrect. PGE's proposal doesn't fairly allocate risks—it dumps them onto customers.
- PGE proposes to change the second principle—that the PCAM should be revenue neutral—to one that says that the PCAM should incorporate reasonable pricing tools to manage long-term customer price volatility.[36] But PGE is changing the PCAM in a way to increase short- and long-term customer price volatility. The dead band and earnings test are the

[35] *See* UE 416 - PGE/400/Sims – Outama/28.
[36] *See* UE 416 - PGE/400/Sims – Outama/29.

key elements to protect customers from price volatility and PGE's proposal guts these protections.

- PGE proposes to change the third principle—that the PCAM should operate over the long-run to balance customer and shareholder interests—to a principle that the mechanism should balance customer and shareholder interests.[37] PGE drops the first part of the principle. But that first part was important. The PCAM was designed to be triggered by unusual circumstances. In stating that it was important that it operate over the long term, the Commission was making clear that parties should not overreact to short-term events. This PCAM was designed to operate under a variety of conditions, and we should not overreact to the current post-COVID unusual market conditions.
- Finally, PGE propose to change the final principle—that the PCAM should provide an incentive to the utility to manage its costs effectively to a principle that the PCAM's design should incentivize efficient operations and management of costs that are within the utility's control.[38] A key element to PGE's change is adding "within the utility's control." Normal business risk is not fully under the utility's control. That is why it is a risk. The utility has professionals managing power costs, buying and selling power in the market, so they have a significant impact on power cost and poor decision making can have negative consequences. But many aspects of the market are outside of their

[37] *See* UE 416 - PGE/400/Sims – Outama/30.
[38] *See* UE 416 – PGE/400/Sims – Outama/30.

control. The current PCAM recognizes this by setting a limit on the utility's exposure to the impact of actual market costs. PGE's principle that we should true up costs that are outside of its control calls for drastically changing ratemaking away from forecasts and shifting more risk to customers. This begs the question of what is the purpose of a for-profit utility with shareholder equity if all business risk falls on customers. Again, without risk, the utility's customers would be better off with debt-financed investments. At a minimum, such a risk shift would run directly counter to the Company's request to increase its ROE in this case.

C. *PCAM Recommendation.*

Shareholder equity sets the risk tolerance of a utility. As equity and ratebase increase—and they have tremendously with PGE, and this will continue—the risk that a utility can absorb grows. Unlike the original PCAM, today, only the earning test is still based on the level of equity. CUB proposes the following:

Earnings Test: The earning test, based on a range of reasonable earnings (100 basis points ± authorized earnings) should not change. It is important to protect customers and ensures that the Company's earnings are within a reasonable range. We should not be changing from forecasted prices when earnings are reasonable.

Dead band**:** The Commission stated in a number of proceedings that the dead band should be based on the amount of equity that a Company has, but as PGE has dramatically increased its equity over the years, there has been no adjustment to the dead band. CUB believes we should return to a deadband based on basis points ROE. The current deadband has shrunk from 150/75 basis points to approximately 50/25 basis points. CUB proposes splitting the difference by setting a dead band of 100/50 basis points.

Sharing: CUB proposes to retain the current sharing percentages at 90/10.

IV. SINGLE-ISSUE RATEMAKING MECHANISMS

Q. What is the purpose of this section?

A. This section addresses the large number of single-issue ratemaking mechanisms that currently exist on PGE's regulated books. This testimony will address the impact that these mechanisms have on ratemaking, their interplay with the Commission's authority and processes, their impact on the risk allocation between the Company and its customers, and recommendations that reduce the incentive for single-issue ratemaking and ensure that utility costs that are billed to customers undergo appropriate scrutiny.

Q. Please summarize your testimony.

A. In this section, I recommend some principles to apply to single issue ratemaking mechanism and recommend eliminating some of PGE's current single issue ratemaking mechanisms. This proposal will help to ensure an equitable risk balance between customers and shareholders by moving more closely to the traditional ratemaking model of utilizing the general rate case process.

The Commission's core responsibility is to ensure that the rates the utility charges its ratepayers are just and reasonable. The review of such rates is undertaken on a holistic basis. In carrying out general rate reviews, the Commission has a long history of using future test years to allow the utility the opportunity to earn its authorized rate of return while balancing the interests of customers and shareholders.

CUB supports restoring the principal use of the general rate case format to set rates on a holistic basis because that process best balances the interests of customers and shareholders. Given that regulation works within an asymmetric information framework, namely that the utility knows more information about its business than does its regulator or customers, utilities already have an advantage with the general rate case model. This is because the utility is able to time its rate cases to coincide with an increasing cost environment; and the utility can use regulatory lag to its benefit when there is a decreasing cost environment. The single-issue ratemaking model further skews the advantage in favor of utility shareholders, because rates are increased without looking at the company as a whole to determine if there are other factors that offset the costs or even warrant a rate decrease.

Q. What is the Commission's mission and mandate?

A. According to the Commission's website, its mission is "[t]o ensure Oregon utility customers have access to safe, reliable, and high quality utility services at just and reasonable rates."[39] Further, ORS 756.040 delineates the general powers vested in the Commission. It states, in part, that "[t]he commission shall balance the interests of the utility investor and the consumer in establishing fair and reasonable rates."[40] In seeking the balance the interests of the utility customer and investor, the Commission's focus is on reasonable overall rates, not cost recovery of individual

[39] Oregon Public Utility Commission, *About Us, available at* https://www.oregon.gov/puc/aboutus/Pages/default.aspx
[40] ORS 756.040(1).

rate elements.[41] Examining costs is essential, but at the end of the day, the focus is on whether the rates charged are just and reasonable and whether the rates charged allow the utility a reasonable return for its shareholders.

Q. What is the origin of "just and reasonable rates"?

A. The "just and reasonable" standard was articulated in a landmark U.S. Supreme Court case entitled *Federal Power Commission v. Hope Natural Gas Co*.[42] As described by the Court, this standard generally requires that the Commission balance the interests of the customer and investor. This means Commission-approved rates must not overcharge the customer to the extent that the rates qualify as an unreasonable exaction; but the rates must also provide the utility with sufficient revenue for both operating expenses and to cover the capital costs of the business so as not to be considered a taking of shareholder property.[43] The Commission has acknowledged this balance:

> The Commission sets rates within a reasonable range that protects the competing interests of the utility and its customers. To protect customers, the rates must be set at a level sufficiently low to avoid unjust and unreasonable exactions. To protect the utility investor, the rates must provide sufficient revenue not only for operating expenses, but also for the capital costs of the business.[44]

Q. How does the Commission establish just and reasonable rates?

A. According to the Commission in Order No. 08-487:

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[41] *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 313-315 (1989) ("The economic judgments required in rate proceedings are often hopelessly complex, and do not admit of a single correct result. The Constitution is not designed to arbitrate these economic niceties. Errors to the detriment of one party may well be canceled out by countervailing errors or allowances in another part of the rate proceeding. The Constitution protects the utility from the net effect of the rate order on its property. Inconsistencies in one aspect of the methodology have no constitutional effect on the utility's property if they are compensated by countervailing factors in some other aspect.").

[42] *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944) (hereinafter *Hope*).

[43] *Id*.

[44] OPUC Order No. 08-487 at 5.

> The Commission sets rates under a comprehensive and flexible regulatory scheme. The legislature has expressed no specific process or method the Commission must use to determine the level of just and reasonable rates, and the Commission has great freedom to determine which of the many possible methods it will use.[45]

Establishing just and reasonable rates is the core responsibility of the Commission, and there is no set process that it must use to accomplish this. The legislature has provided the Commission with "the broadest authority—commensurate with that of the legislature itself—for the exercise of [this] regulatory function."[46] Therefore, the Commission has tremendous authority—and discretion—to set just and reasonable rates and is bound by no specific method, nor is any single element dispositive.

In a general rate case, the Commission has an established formula for how it sets the revenue requirement used to determine the rates charged to customers:[47]

> **REVENUE REQUIREMENT** – Revenues determined to be necessary to allow the company to recover reasonable expenses and the opportunity to earn a reasonable rate of return on its prudent rate base.
>
> **REVENUE REQUIREMENT FORMULA** $R = E + (v - d)\,r$
>
> ***R*** – Total revenue required
> ***E*** – Operating expenses
> ***v*** – Original cost of utility assets (value of rate base)
> ***d*** – Accumulated depreciation of utility assets (plant depreciation)
> ***r*** – Rate of return

The Commission uses this formula to identify the revenue needed to compensate the utility for its operating costs and for a return on its rate base. Importantly, if

[45] *Id.*
[46] *Id.* at 4.
[47] OPUC, Guide For Filing a Water Utility Rate Case, page 2, *available at* https://www.oregon.gov/puc/forms/Forms%20and%20Reports/Application-for-Utility-Rate-Increase-Decrease.docx. This same formula is used for electric and natural gas rate case proceedings.

the utility is fully recovering its revenue requirement, it is being fairly compensated for its operating costs and a return on its rate base.

But this formula is not limited to new costs. It does start with existing costs and layer on new costs. It is not:

$$R = \text{old } R + \text{new } E + (\text{new } V \text{- new } d)r$$

The formula looks at the total costs to the utility and sets a revenue requirement adequate to recover those costs while allowing the utility a reasonable return on its capital investment. This formula should produce just and reasonable rates.[48]

Unfortunately, there has been an increase in the amount of costs that are placed in rates through tracking mechanisms and other single-issue ratemaking mechanisms rather than through general rate cases. CUB is concerned that the regulatory environment has developed an incentive for single-issue ratemaking, and that single-issue trackers do not undergo the scrutiny necessary to ensure just and reasonable rates.

Q. Please explain.

A. I am a PGE customer. My monthly bill has 18 different individual line items for costs/refunds that are not part of the basic charge, and the normal energy, distribution, and transmission charges that come out of a general rate case. They are simply utility costs that PGE has been allowed to put into single-issue trackers.

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[48] The Commission also looks at affordability when establishing rates and has stated that due to large increases that cause rate shock it can set revenue requirement at the lowest level that is reasonable or adjust the timing of rate recovery.

Let's look at Schedule 110, the Energy Efficiency Customer Service Tariff. The purpose of the tariff is:

> To fund Company activities associated with enabling Customers to achieve energy efficiency including, but not limited to project facilitation, technical assistance, education and assistance to support programs administered by the Energy Trust of Oregon (ETO).[49]

This is a tariff with a balancing account. This balancing account was established in 2008 and has continued since that time.[50] The cap on expenses is $1.3 million and the Company routinely projects spending of $1.3 million.[51] Essentially Schedule 110 is a balancing account wrapped around $1.3 million of revenue requirement. Due to limitations on outreach activities during COVID, the balancing account had a surplus of $1.4 million, but was forecast to spend the full amount under the cap in 2023.[52]

Q. Is this an Automatic Adjustment Clause (AAC)?

A. Maybe. It certainly acts like an AAC. In docket UE 412, CUB asked PGE to provide a list of all current AACs and this was not on the list.[53] In a bench request in this docket, the Commission asked for a list of AAC, amortizations, or rate adjustments addressed outside of this docket that are proposed to change on January 1, 2024. PGE listed Schedule 110 and identified it as a Deferral + AAC. However, neither the tariff nor Advice No. 22-33 mention anything about an

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[49] *See* PGE Tariff Schedules, Schedule 110, https://porlandgeneral.com/about/info/rates-and-regulator/tariff
[50] *See* Advice filing 22-33, Public Utility Commission of Oregon Staff Report, Public Meeting Date: December 13, 2022.
[51] *See* PGE Tariff Schedules, Schedule 110.
[52] *See* PGE Advice Filing 22-33.
[53] *See* UE 412, CUB Exhibit 200.

underlying AAC or a deferral. What is clear is that this is a single-issue ratemaking mechanism with an underlying balancing account that uses retroactive adjustments to charge customers the costs associated with a very limited set of energy efficiency (EE) promotions. It acts similar to an AAC, but whether it was ever approved as an AAC is not clear.

Q. What is the background on this tariff?

A. I remember the development of this tariff. In 2007, a coalition of organizations, including CUB and PGE, helped develop SB 838, the RPS. The original bill did not include anything related to EE. During the session, PGE proposed using the bill to expand EE for residential and small commercial customers. PGE said that there was some cost-effective EE, particularly on the residential side, that was not being achieved through the 3% public purposes fund and that this bill would be a good opportunity to authorize some additional funding. CUB supported this idea and supported the bill with this addition.

After the session, it became clear that CUB, Commission Staff, and PGE had very different views on how to implement this additional EE acquisition. PGE felt very strongly that the purpose of this bill was to allow them to get back in the EE business and provide the additional EE, which was beyond what the Energy Trust of Oregon (ETO) was achieving within the 3% public purpose charge. CUB and Staff thought that the ETO should provide the additional EE programs. This led to a set of negotiations where PGE proposed various EE programs that it wanted to conduct, such as developing an EE curriculum for public schools. CUB was concerned that it would be impossible to understand whether such a program was cost effective and was concerned that PGE was not an expert in school curriculum. In the end, we agreed that PGE and PAC would be allowed to fund some limited staff time to promote EE and funnel interested customers to the ETO. From CUB's perspective, allowing Schedule 110 was the "tax" we had to pay to the utility to get agreement that would allow the bulk of the SB 838 EE programs to be administered through the ETO.

Q. Has this tariff been reviewed by the Commission?

A. Yes and no. PGE makes an annual presentation to the Commission titled SB 838 Marketing and Outreach Efforts, alongside the June ETO presentation, so the content of what PGE is doing is reviewed. However, in these presentations, the underlying tariff itself, is not generally discussed. The tariff does show up at Commission meetings as part of the consent agenda in filings such as Advice No. 22-33, when the billing rate had to be changed due to the COVID overcollection and Advice No. 19-19, where it was part of a series of tariff changes labeled housekeeping. While the tariff has been before the Commission in various settings, it may not been substantively reviewed.

Q. Why is the tariff funded through a separate balancing account and not through base rates?

A. In 2008, the tariff was necessary to establish ETO as the entity that acquires additional EE beyond the public purpose charge. PGE wanted to do its own EE activities and the cap on this tariff limited those activities and ensured that the ETO was the entity that conducts EE programs. But today, 15 years later, there does not seem to be a reason. While SB 838 had provisions concerning cost recovery for renewable resources and associated transmission, the EE part of SB 838 was not included. There is no barrier to placing this in base rates. It seems that as a predictable on-going $1.3 million cost it would easily fit into base rates. It is not clear whether anytime in the last 13 years PGE has had to justify this tracker and defend why it exists.

And that is one of the big problems with trackers. They exist in perpetuity without the utility ever having to justify their continued existence. The fact that earlier this year in UE 412 PGE "based on a review of its tariffs" did not identify this as an AAC, and in this docket is identifying it as an AAC, suggests that there is not a comprehensive list of all AACs, deferrals and other single-issue trackers. Further, while ORS 757.210(1)(b) provides that AACs should be subject to Commission review at least once every two years, this rarely occurs in practice. The number of single-issue trackers, coupled with the infrequency in which they are revisited, makes the role of the Commission and stakeholders to establish just and reasonable rates more difficult.

Q. What are the problems with trackers?

A. There are several problems with trackers:

- First, we need to understand the totality of the trackers that are out there. When CUB asked for a list in the wildfire docket, PGE had to conduct a review of its tariffs, suggesting that it is not tracking this. The Commission asked for this information in a bench request in this docket. When the consumer advocate, the utility and the regulator don't know the full extent of single issue trackers, there is a problem.

- Second, there needs to be a process to ensure that trackers are scrutinized. Assuming that they will be reviewed regularly is not enough, nor is having them on the consent agenda. There needs to be a process to ensure that they continue to be justified.
- Third, the biggest problem is that, for utilities, trackers are more favorable than forecasted costs being recovered with forecasted loads creating an incentive for single-issue ratemaking. Rather than forecasting a cost, a tracker allows the actual cost to be placed in rates. Rather than basing prices on forecasted loads, trackers allow prices to be adjusted until the actual cost is recovered on a dollar-for-dollar basis. This eliminates much of the ratemaking risk for utilities and effectively shifts it onto customers.
- Unless there is an earning test associated with a tracker, utilities are allowed to raise rates to recover the tracker, even when rates are sufficient to recover the cost without a rate change. This will lead to higher rates than would exist from general rate cases, where we forecast recovery of prudently incurred costs and a reasonable return and use that forecast to set prices.

Q. What are CUB's recommendations for treatment of trackers?

A. CUB as several recommendations:

- Utilities should file an annual report that lists every AAC, deferral, and tracker that exists within its system, the purpose of the tracker, the costs associated with that tracker. As an initial step, CUB recommends that PGE be subject to this requirement.

- All trackers should have sunset dates of not more than 3 years from their inception. Once the sunset date is reached, the Company must justify continuing the tracker in the next general rate case in opening testimony. In this review, the utility must bear the burden of proof, including demonstrating why this particular cost should be handled through a tracker rather than base rates.
- There should be a presumption of an earning test on each tracker unless the utility can meet its burden to prove that there should not be. The earnings test should include an earnings band that defines reasonable earnings and rate changes should only be applied when earnings deviate from that reasonable range.
- Schedule 110 should be eliminated. Any negative amount left in the balancing account should be refunded to customers and the tariff should be eliminated. If PGE believes these costs are prudent and recoverable, it can make the case to place them in base rates.
- Schedule 112 is the Customer Engagement Transformation Adjustment. This supplemental schedule recovers 2014 – 2015 deferred costs and 2017 and 2018 O&M costs associated with PGE's Customer Engagement Transformation (CET) project. CUB has confirmed that this supplement schedule was removed from customers' bills on January 31st, 2023, as

indicated in the tariff. CUB recommends that the rate schedule be removed from PGE's tariff book.

- Schedule 134 is the rate schedule that covers the Gresham Retroactive Privilege Tax Payment Adjustment. CUB recommends that the rate schedule be terminated. The Company agrees with CUB's recommendation.[54]
- Schedule 138 is the rate schedule that covers the revenue requirement associated with battery storage projects procured subject to UM 1856.[55] CUB recommends that the Company justify keeping this rate schedule in its next general rate case and why specific projects cannot be moved into base rates.
- Schedule 145 is the rate schedule that covers expenses related to decommissioning of the Boardman Power Plant. The Company has indicated that decommissioning of Boardman be complete by the end of 2023.[56] CUB recommends that the Company justify keeping this rate schedule in its next general rate case.

V. TRACKERS FOR RFP IE AND THIRD-PARTY CONSULTANTS

Q. Please summarize your testimony on this subject.

A. CUB recommends that costs associated with the RFP IE and any third-party consultants be placed into base rates.

Q. What costs are CUB's recommending placing into base rates?

A. PGE is required to issue an RFP for all major resource acquisitions—those with durations greater than five years and quantities greater than 100 MW. As a part of

[54] UE 416 – CUB/203.
[55] UE 416 – CUB/204.
[56] UE 416 – CUB/205– CUB DR 112.

this process, an IE is required to be used to assess the procurement process. CUB is recommending that the cost of IEs for the RFP be placed into base rates. Once costs associated with the IE are collected in base rates, CUB recommends that PGE no longer be allowed to defer IE costs once this cost item is being moved into base rates.

Q. How has PGE conducted cost recovery of the costs of the RFP IEs and third-party consultants in the past ten years?

A. From 2011 to 2023, PGE has filed five deferrals to handle the costs of IEs.[57] The Company has received approval from the Commission for all deferrals associated with the RFP IE.

Q. Is PGE's cost recovery method for RFP IE costs an AAC?

A. No. Instead of using an AAC, PGE files a deferral before each RFP.

Q. What are the advantages of tracking these costs via a deferral for the Company?

A. Rather than forecasting a cost, the RPF IE deferrals allows the actual cost to be placed in rates. Rather than basing prices on forecasted loads, PGE's IE cost recovery method allows prices to be adjusted to enable dollar-for-dollar cost recovery. This method is also favorable to the company because they earn a regulated profit on deferred revenues prior to amortization.

Q. Why is it time to move these costs into base rates?

A. For more than a decade, PGE has had to conduct RFPs and to hire IEs. PGE hiring an IE and consultants to evaluate its RFP is normal, forecastable part of its

[57] UE 416 – CUB/206.

business. This cost item is not of the magnitude to justify having the Commission approve a deferral when it can be normalized into base rates.

Q. What is the magnitude of this cost?

A. For the 2021 RFP, PGE currently has a cost of $410,000.

Q. Is CUB able to include an estimate of this expense?

A. Not currently. CUB issued discovery to estimate a normalized estimate of this cost to project the cost of the IEs in base rates. To place this cost into base rates, CUB needed information about cadence of RFPs over the next five years to normalize the IE expense into base rates. The Company indicated that the information needed to normalize this cost would occur on July 17, 2023.[58] On rebuttal, CUB will provide a normalized estimate of this cost to include in base rates.

V. SEPARATING DEFERRALS AND AUTOMATIC ADJUSTMENT CLAUSES (AACs)

Q. What is the purpose of this section of your testimony?

A. My testimony responds to PGE's proposal detailed in PGE/1400 to 1) limit deferral applications and reauthorizations to those that are specifically required under ORS 757.259; and 2) have the Commission rule that AACs established under ORS 757.210 be recognized as exceptions to ORS 757.259.[59] PGE is asking the Commission to rule that deferrals and AACs are separate and distinct.

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[58] UE 416 – CUB/206.
[59] UE 416 – PGE/1400/Ferchland – Batzler/1, lines 17-20.

Q. Why does PGE believe these changes are warranted?

A. To PGE, these changes are warranted because it believes that the current process by which Commission Staff requires PGE to file deferral applications when an AAC has been established is administratively burdensome and unnecessarily duplicative.[60] PGE disagrees with Staff's interpretation of the deferral (ORS 757.259) and AAC (ORS 757.210) statutes and states that there is no clear legal, policy, or accounting basis to require that an approved AAC must have an associated deferral filing.[61] According to the Company, deferrals under ORS 757.259 are meant to manage certain instances of unforeseen costs between GRCs, while AACs filed under ORS 757.210 are meant to allow for the "*contemporaneous* collection of costs while the expenses are incurred for the activity and allows for rate increases or decreases to reflect such expenses without a prior hearing."[62] PGE further draws a distinction between the two because, "[u]nlike a deferral where amounts build up and are then *later* included in rates, an AAC is meant to collect costs at the same time the costs are incurred."[63]

Q. Please summarize your recommendations.

A. At this time, CUB does not believe the Commission should adopt the Company's proposed change to its policy requiring that a deferral accompany and underlie an AAC. While CUB does not disagree that moving away from this practice would be less administratively burdensome, CUB believes PGE is looking at this issue too narrowly and is failing to consider the wider range of regulatory applications that

[60] *Id.* at lines 8-13.
[61] *Id*. at 4.
[62] *Id*. at 4-5 (emphasis in original).
[63] *Id*. at 5, lines 19-20.

deferrals are used for and the actual reasons why deferrals have traditionally accompanied AACs.

Q. Please explain.

A. CUB will appropriately reserve arguments related to statutory interpretation or other legal issues for briefing. However, PGE fails to address a number of policy and ratemaking considerations that undercut its position detailed in testimony.

First, while PGE asserts that deferrals might initially be needed to address retroactive ratemaking concerns, it states that "once the AAC tariff is in place, costs or revenues would be collected or refunded contemporaneously and the deferral would no longer be needed to address retroactive ratemaking."[64] However, PGE fails to recognize that the deferred accounting statute is the only statutorily authorized exception to the prohibition against retroactive ratemaking, and is the only means by which a utility can capture and track costs and revenues and pass them to customers until a later time.[65] Therefore, any AAC that includes a tracker to potentially true-up any deviations from the initial AAC forecast *must* include a deferral that underlies the AAC and tracks actual costs. Several of PGE's AAC's, including the recently-approved Wildfire Mitigation Plan AAC, include a true-up of actual costs. Since deferrals are the only statutory exception to the prohibition against retroactive ratemaking, a subsequent AAC true-up would not be possible without an underlying deferral. While PGE draws a distinction between AACs and

[64] UE 416 – PGE/100/Ferchland – Batzler/8, lines 11-16.

[65] OPUC Order No. 05-1070 at 1 ("Deferred accounts provide a means to address utility expenses or revenues outside of the utility's general rate case proceeding and are a statutorily authorized exception to the general prohibition against retroactive ratemaking.").

deferrals insofar as AACs allow for contemporaneous cost recovery,[66] it fails to recognize the impact of AACs that also include a subsequent potential true-up. Not only would the utility be unable to true-up any potential cost deviations from the forecast, the Commission would be precluded from placing an earnings test on amounts recovered through an AAC, which the Commission has held "does not interfere with the ability of the parties to recover their costs and instead merely shows that they have not over-earned."[67] By examining a utility's holistic earnings before determining whether a subsequent true-up is warranted, an earnings test can serve an important regulatory purpose. A subsequent true-up with an earnings test associated with it can also help ensure utilities retain an important incentive to operate efficiently.[68]

Second, PGE places outsized importance on the traditional role for the deferred accounting mechanism—filing them prior to or just as expenses are incurred for activities that were unknown and/or unexpected at the time of setting rates.[69] While technically accurate in addressing one application for deferrals, this overly-narrow view fails to consider the wide range of regulatory applications that deferred accounting mechanisms are used for. For almost 40 years:

> the Commission has used deferred accounting to benefit both ratepayers . . . and utilities . . . . The Commission has used deferrals for a variety of reasons, including to: address costs that are hard to forecast or arise from extraordinary and unanticipated events; implement legislative mandates or

[66] UE 416 – PGE/1400/Ferchland – Batzler/1, lines 17-20.
[67] OPUC Order No. 23-173 at 6.
[68] Or. Op. Atty. Gen. OP-6076 (1987) at 11 ("Utilities would have no incentive to operate efficiently because their rate of return would be insured by an eventual surcharge against ratepayers. The cost to consumers, therefore, would rise. Regulators must allow regulated utilities an opportunity to earn a reasonable rate of return. Regulators cannot ensure that utilities will earn a reasonable rate of return.").
[69] UE 416 – PGE/1400/Ferchland – Batzler/4.

> unique ratemaking mechanisms; and encourage utility or customer behavior consistent with regulatory policy.[70]

Therefore, the narrow application that PGE relies upon is only one reason why deferred accounting applications are used in Oregon utility regulation. The Commission uses deferrals associated with AACs to both protect utilities and customers from unnecessary costs and to encourage efficient operations—a behavior that is consistent with sound regulatory policy. PGE's narrow view fails to consider the benefits to its shareholders, customers, and utility regulation as a whole that can accrue when deferrals are used to track actual costs to compare to the forecast used in an AAC.

Q. PGE is asking that the Commission recognize deferrals and AACs as distinct mechanisms. Aren't they distinct already?

A. Yes. As PGE notes, the two mechanisms are different and are governed by different statutes. AACs are tariffs filed under ORS 757.210, while deferrals are filed under ORS 757.259. Even though they are distinct, a deferral is needed alongside an AAC to track costs for later potential true-up and to ensure that an earnings test can be applied.

Q. CUB is also seeking to limit PGE's total number of single-issue mechanisms. Why are you advocating here to retain deferrals in certain circumstances?

A. They serve an important regulatory function and enable the Commission to consider the impact of single-issue ratemaking mechanisms on holistic cost recovery.

[70] OPUC Order No. 05-1070 at 1.

Q. PGE argues that the Commission would still be able to review all costs (both forecasts and actuals) for prudence if a deferral does not accompany an AAC. Do you agree?

A. No. Deferrals are the only statutory exception to the rule against retroactive ratemaking, and the Commission would not be able to review actual costs for prudence if a deferral is not used. Instead, both the utility and customers would be limited to addressing the costs used in the forecast of the AAC at its outset.

Q. PGE argues that many of its deferrals are unnecessary and can likely be addressed through other regulatory processes. Do you agree?

A. Yes—it is likely that many of its ongoing deferrals can be either rolled into base rates or eliminated entirely. This is addressed in CUB's testimony regarding the total number of single-issue ratemaking mechanisms on the Company's system. However, any AAC that includes a tracker for later potential true-up must include an underlying deferral in order to comply with the prohibition against retroactive ratemaking.

Q. What is the prohibition against retroactive ratemaking?

A. In the 1987 Attorney General (AG) Opinion to the Commission that gave rise to the deferred accounting statute, AG Dave Frohnmayer described retroactive ratemaking as "the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established."[71] According to the AG's Opinion, the:

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[71] Or. Op. Atty. Gen. OP-6076 (1987) at 1 citing *State ex rel Util. Consumers Council v. P.S.C.*, 585 SW2d 41, 59 (Mo 1979).

> rule protects ratepayers by ensuring that they know the maximum cost of service at the time they use the service. The rule also promotes efficiency by the utilities in two ways. First, the utility is encouraged to keep costs down because it cannot recoup its excess past or present costs in the future. Second, if the utility's cost containment measures result in unexpected profits for the utility, those profits are a bonus to the utility that cannot be taken from it.[72]

In the Opinion, the AG determined that the Commission lacked authority to defer past expenses for later recovery at the time the Opinion was issued. Shortly thereafter, the ORS 757.259 deferral statute was passed through the Oregon legislature. It remains the only exception to the strict prohibition against retroactive ratemaking. Again, absent a deferral, the Commission, stakeholders, and utilities have no ability to include actual AAC amounts in rates and must stick to the amounts examined in the forecast stage.

Q. What is your recommendation?

A. The Commission should decline to adopt PGE's recommendation and should continue to include deferrals alongside AACs when they are necessary—i.e. where there is a later potential true-up.

VI. SCHEDULE 122 (ASSOCIATED ENERGY STORAGE IN RAC)

Q. What is the purpose of this section of your testimony?

A. My testimony addresses and responds to arguments raised in PGE/1300 surrounding the treatment of energy storage resources in its Schedule 122 renewable energy resources automatic adjustment clause (RAC). In its testimony, PGE requests that the Commission clarify that standalone energy storage that is used to integrate and firm renewables on a utility's system qualifies as "associated

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[72] *Id*. at 2.

energy storage."[73] A ruling in PGE's favor would enable the Company to include essentially any energy storage resource on its system in its RAC filing, which would allow for potential cost recovery outside of the setting of holistic rates in a general rate case.

Q. Please summarize your testimony.

A. CUB disagrees with the Company's broad interpretation of the word "associated," which would allow any energy storage resource used to integrate and firm renewables to be considered a Renewable Portfolio Standard (RPS) compliant resource that would be eligible for cost recovery under the RAC. Consistent with our position on this issue in PGE's UE 335 general rate case proceeding, CUB continues to believe that "associated energy storage" should be defined as storage that is located on-site with an RPS-eligible resource that adds value to the underlying renewable resource. PGE's proposal draws no clear distinction between various storage resources and is likely to lead to poor policy and ratemaking outcomes.

Q. What is the RAC?

A. The RAC is an AAC that enables utilities to recover the cost of renewable energy resources used for RPS compliance. SB 838, Oregon's original RPS, gave the Commission authority to establish this AAC. The RAC's contours were established in Order No. 07-572. The RAC enables the utility to avoid regulatory lag on qualifying renewable resources. SB 1547 broadened the RAC to include "associated energy storage," and PGE added this language to its Schedule 122 RAC in its UE

[73] UE 416 – PGE/1300/Macfarlane – Pleasant/45.

335 general rate case proceeding. However, the legislative intent and meaning of "associated" in this context remains a live issue.

After proposing an inappropriately broad definition of "associated" to include any storage project used to integrate renewables in dockets UM 1856 and UE 335, this is the third time PGE has brought the proposal before the Commission. CUB opposed both prior proposals, and we continue to oppose PGE's proposal in this proceeding.

Q. What are the poor policy and ratemaking outcomes you reference?

A. Approving PGE's interpretation of "associated energy storage" to include "standalone storage that is used to integrate and firm renewable on a utility's system"[74] would enable the Company to include conceivably any energy storage resource on its system in the RAC. The RAC is a single-issue ratemaking mechanism that enables the Company to avoid regulatory lag and allows it to update its rates without any holistic consideration of its system-wide earnings. Mechanisms like the RAC shift both cost and risk away from PGE's shareholders onto its customers. As PGE makes movement toward the RPS, the vast majority of PGE's renewable generation additions resources will be eligible for inclusion in the RAC. By inappropriately broadening the definition of "associated energy storage," all of the Company's total new resources will be eligible for cost recovery in a single-issue ratemaking mechanism that does not contain an earnings test, which shifts risk and cost away from the Company and onto customers.

[74] UE 416 – PGE/1300/Macfarlane – Pleasant/45.

Q. CUB was involved in the negotiation and ultimate passage of SB 1547, the law that expanded the provisions allowing for the RAC to include "associated energy storage." Do you believe the intent of the law was to include any storage project that helps integrate renewables in the RAC?

A. Any final decision on the legislature's intent in including "associated energy storage" will ultimately require a legal determination and appropriate statutory construction analysis. CUB will appropriately reserve those arguments for legal briefing. However, from CUB's direct experience in negotiation SB 1547, the purpose of the RAC was not to recover the cost of integrating renewables. Port Westward 2 was developed for the purpose of integrating renewables.[75] The Company's participation in the Energy Imbalance Market contributes to integrating renewables. Future demand response programs will likely contribute to integrating renewables. The RAC should not be expanded to include any of these items.

Further, in addition to "associated energy storage," ORS 469A.120(2)(a) allows for "associated electricity transmission" to be included in the RAC. Under PGE's proposed definition for "associated," arguably any transmission project on the Company's system could be eligible for inclusion in the RAC, since all of PGE's transmission is going to be used to move renewable electricity through PGE's balancing authority. This was clearly not the legislature's intent in including "associated" transmission and storage in Oregon's RPS and RAC.

[75] https://www.portlandgeneral.com/our-company/news-room/news-releases/2015/01-02-2015-new-pgeplant-will-help-balance-renewables-and-meet-peak-demand

A more reasonable definition, CUB would submit, is for energy storage projects that are physically on-site with RPS-eligible renewable resources that add to the underlying renewable resource's capacity factor or otherwise add value to the project.

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

Column	A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Year	Total Operating Revenues	Average Rate Base (Regulated Utility)	150 basis points 50/50 cap structure	PUC applied deadband in basis points	NVPC from ROO	NVPC percent of revenues	NVPC from PCAM (revised actual)	NVPC (forecasted)	Operating Revenues	Utility Plant	total generation MWH	Net purchased Energy MWH	Sales to ultimate customers MWH
	2001	NA	NA	NA	NA	NA	NA	NA	NA	2,433,340,282	3,498,986,622	12,330,618	17,720,652	19,040,188
	2002	NA	NA	NA	NA	NA	NA	NA	NA	1,722,235,758	3,625,250,480	7,625,096	24,935,250	18,771,884
	2003	NA	NA	NA	NA	NA	NA	NA	NA	1,841,286,654	3,744,478,636	7,921,607	23,908,042	18,425,854
	2004	NA	NA	NA	NA	NA	NA	NA	NA	1,750,260,219	3,878,291,568	8,114,299	20,158,386	17,764,138
	2005	NA	NA	NA	NA	NA	NA	NA	NA	1,983,275,708	4,047,611,448	7,820,908	22,604,193	17,540,047
	2006	NA	NA	NA	NA	NA	NA	NA	NA	2,035,396,471	4,170,041,341	7,208,894	26,224,528	18,432,527
	2007	1,533,259,000	4,447,289,000	16,677,334	150	698,003,000	45.5%	$ 638,942,638	673,708,526	2,234,048,531	4,898,550,533	10,403,655	21,190,869	17,461,742
	2008	1,564,763,000	4,959,690,000	37,197,675	150	729,568,000	46.6%	646,958,000	685,152,000	2,081,478,742	5,060,855,525	11,657,580	15,968,552	17,575,806
	2009	1,633,277,000	5,274,929,000	39,561,968	150	799,285,000	48.9%	793,417,000	814,519,000	1,965,977,746	5,594,743,122	10,587,395	15,550,554	17,419,212
	2010	1,678,948,000	5,894,073,000	44,205,548	150	662,284,000	39.4%	715,699,000	765,923,000	1,935,745,889	6,273,112,149	12,064,862	13,556,311	17,683,065
	2011	1,752,633,000	6,390,390,000	47,927,925	93.89	689,904,000	39.4%	668,567,000	706,106,000	1,832,467,476	6,590,485,297	9,412,087	13,027,363	18,356,826
	2012	1,740,028,000	6,635,324,000	49,764,930	90.43	669,565,000	38.5%	649,744,000	686,612,000	1,823,171,165	6,806,135,364	9,559,421	12,654,253	17,944,435
	2013	1,714,571,000	6,872,583,000	51,544,373	87.30	661,470,000	38.6%	637,393,000	637,348,000	1,845,416,891	7,090,483,780	10,290,898	12,159,558	17,673,447
	2014	1,786,953,000	7,225,239,000	54,189,293	83.04	607,486,000	34.0%	594,248,000	617,944,000	1,926,578,668	8,301,464,412	10,817,321	11,392,970	17,603,187
	2015	1,797,012,000	8,478,837,000	63,591,278	70.76	555,573,000	30.9%	542,989,000	551,682,000	1,914,921,070	8,722,574,599	12,152,016	9,841,229	17,696,386
	2016	1,807,465,000	9,159,444,000	68,695,830	65.51	503,228,000	27.8%	497,826,000	524,106,000	1,939,166,814	9,701,607,393	12,844,073	9,452,614	17,248,173
	2017	1,884,417,000	9,845,463,000	73,840,973	60.94	474,621,000	25.2%	399,990,000	374,624,000	2,022,693,552	10,081,537,481	12,987,082	9,487,631	17,754,280
	2018	1,811,707,000	10,297,341,000	77,230,058	58.27	400,440,000	22.1%	335,457,000	340,976,000	2,005,110,043	10,513,713,376	13,970,664	9,002,682	17,186,001
	2019	1,921,241,000	10,666,490,000	79,998,675	56.25	431,424,000	22.5%	358,376,000	353,665,000	2,147,982,409	11,146,578,388	15,871,590	7,811,844	17,304,691
	2020	1,959,589,000	11,027,490,000	82,706,175	54.41	422,827,000	21.6%	367,670,956	386,430,576	2,157,212,368	11,014,910,106	14,576,632	13,551,511	17,423,803
	2021	2,118,760,000	11,024,363,000	82,682,723	54.42	572,093,000	27.0%	524,210,000	450,531,000	2,415,154,366	11,855,629,261	14,754,100	11,053,274	18,296,054
	2022	2,254,009,000	11,604,965,000	87,037,238	51.70	629,285,000	27.9%							

Columns B,C, and F are from the Company's Results of Operations
Columns H and I are from annual PCAM filings
Columns J,K,L,M, and N are from the Annual PUC Statistic Book

May 30, 2023

To: William Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to CUB Data Request 114
Dated May 15, 2023

Request:

Refer to Schedule 134, what criteria needs to be met before the Company seeks the cancellation of Schedule 134?

a. Does the Company expect to incur any additional revenue from this rate schedule? Please provide a narrative explanation.

Response:

Schedule 134 can be Terminated now, there are no remaining amounts to be amortized through this schedule. The price is current set to zero.

May 30, 2023

To: William Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to CUB Data Request 113
Dated May 15, 2023

<u>Request:</u>

Refer to Schedule 138, what criteria needs to be met before the Company seeks the cancelation of the HB 2193 Energy Storage Cost Recovery Mechanism, and allow costs associated HB 2193 storage pilots to be tracked in base rates? When does the Company expect to cancel Schedule 138?

<u>Response:</u>

The HB 2193 Energy Storage Cost Recovery Mechanism resulted in multiple projects approved through Docket No. UM 1856. PGE pursued a RAC filing for the first of these projects through Docket No. UE 370/372, and all participating parties agreed that PGE could recover all UM 1856 storage projects through the automatic adjustment clause mechanism. Once these projects have been completed and/or are no longer pilot projects and the residential pilot is complete, PGE will review the continuing need for Schedule 138.

May 30, 2023

To: William Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to CUB Data Request 112
Dated May 15, 2023

Request:

Refer to Schedule 145, what criteria needs to be met before the Company seeks the cancelation of Schedule 145?

a. Does the Company expect to incur any additional revenue from this rate schedule? Please provide a narrative explanation.

Response:

PGE is still in the process of completing Boardman decommissioning. We currently anticipate the completion of these activities to largely be complete in the later part of 2023. Following this, PGE will be able to perform a full reconciliation of amounts collected versus amounts incurred to fully decommission the Boardman facility. At this point, the only on-going cost will be for the groundwater monitoring requirements and it would be likely that PGE could then terminate this schedule.

a. No. based on PGE's current knowledge, amounts collected are sufficient to cover the full decommissioning related costs.

May 30, 2023

To: William Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to CUB Data Request 107
Dated May 15, 2023

Request:

Refer to UM 2281, Application for Deferred Accounting of Certain Expenses Associated with an Independent Evaluator and Third-Party Consultants for a Request for Proposal,

a. Please provide the Company's projection for IE and Third-Party expert costs that would be recorded to FERC account 923 for PGE's next RFP by year, in the absence of a deferred accounting order. Please provide the workbooks used to calculate projection.
b. What are the Company's current expectations for the cadence of RFP between 2024 and 2030? Please detail which years the Company expects to have an RFP between 2024 and 2030.

Response:

a. The amounts incurred for 2023 will depend on the amount of work the IE and third-party consultants are required to perform within the 2023 RFP, which is not currently known at this time and can vary within each RFP. For reference, the current balance PGE has deferred associated with IE and third-party consultant costs (net of bidder fees and excluding interest) in PGE's 2021 RFP is approximately $410,000.
b. PGE objects to this request on the basis that it requests new analysis. Without waiving its objection, PGE responds as follows: PGE will be providing details regarding its projected procurement cycle pursuant to Commission Order No. 23-146 on or before July 17, 2023, at which point PGE will supplement this response.

I. INTRODUCTION

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

A. My name is William Gehrke. I am a Senior Economist employed 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. My testimony responds to issues and arguments raised by Portland General Electric (PGE or the Company) in this proceeding on a variety of issues listed below.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- II. Biglow Blade Liberation
- III. Carty Air Intake Fire
- IV. Amazon Pay
- V. Employee Discount
- VI. Rate Design – Residential Rate Design
- VII. Rate Design – Residential
- VIII. Rate Design – TOU Rates
- IX. Rate Design – TOD Rates
- X. Rate Spread – Schedule 118 and Schedule 115

II. BIGLOW BLADE LIBERATION

Q. Please summarize your testimony on this subject.

A. CUB recommends a disallowance of **(Start Highly Confidential)** [redacted]

[redacted] **(End Highly Confidential)** at the Company's Biglow Wind Farm (Biglow).

Q. Please provide some background information on Biglow.

A. Biglow is a 450 MW wind farm located in Sherman County, Oregon. The facility is owned by PGE. The project was completed in 2010 and was built in three phases.

Q. What was the incident at Biglow?

A. At 2:11 AM on February 1st, 2022, Biglow's Turbine 71 experienced a blade liberation event where one of its blades became detached and was thrown from the tower and landed in a field 100 yards away.[1] In response to the blade liberation, the Company completely shut down operations at Biglow Phase 1 to access the facility.

Q. Please briefly describe who is responsible for maintenance and service at Biglow.

A. Biglow's maintaince and service has been conducted **(Start Highly Confidential)** [redacted] **(End Highly Confidential)**[2]

Q. What was the cause of the blade liberation at Biglow's Turbine 71?

A. The direct cause **(Start Highly Confidential)** [redacted]

[1] UE 416 – CUB/301.
[2] UE 416 – CUB/103/Gehrke/10.

[redacted] **(End Highly Confidential)**[3] PGE's own internal analysis indicates that this incident was the result of **(Start Highly Confidential)** [redacted] **(End Highly Confidential)**

(Start Highly Confidential) [redacted] **(End Highly Confidential)**

As part of the Company's investigation process, PGE **(Start Highly Confidential)** [redacted] **(End Highly Confidential)**[4] **(Start Highly Confidential)** [redacted]

[3] UE 416 – CUB/103/Gehrke/16.
[4] UE 416 – CUB/103/Gehrke/10.

[redacted] **(End Highly Confidential)**[5].

Q. What are the types of costs that the Company incurred from the Biglow blade liberation incident?

A. Portland General Electric has incurred **(Start Highly Confidential)** [redacted] **(End Highly Confidential)**

Q. What is PGE's proposal around these costs?

A. (Start Highly Confidential) [redacted] **(End Highly Confidential)**[6] This is the amount CUB seeks a disallowance for in this proceeding.

Q. What has customers' role been regarding Biglow?

A. Customers are currently paying in rates the annual costs associated with Biglow. For more than 15 years, customers have been fully funding the operation and maintenance costs and the capital costs associated with Biglow with an understanding that the facility would be adequately maintained to provide benefits to customers.

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[5] UE 416 – CUB/103/Gehrke/13.
[6] UE 416 – CUB/302.

Biglow was not procured under a purchased power agreement, but, rather, is owned by PGE. PGE's investors have financed the capital costs associated with Biglow. Through base rates, retail customers have been paying off the balance associated with Biglow over the life of the project. In exchange for providing the capital needed to build Biglow and managing Biglow, PGE is allowed the opportunity to earn a profit on investments made in Biglow through customer rates. PGE's shareholders have and will continue to benefit from the profit Biglow provides.

Q. Given customers' role in Biglow, should customers pay for these costs?

A. No. Customers have paid rates that include forecasted costs associated with maintenance over the life of Biglow through base rates. While **(Start Highly Confidential)** [redacted] **(End Highly Confidential**) customers should not be expected to be responsible for **(Start Highly Confidential)** [redacted] **(End Highly Confidential)**. That responsibility lies with the Company, and PGE has a responsibility to ensure the continued operation of ratepayer-funded resources like Biglow. It is inappropriate to place this cost on customers. The utility is meant to be manager of the system. The Company **(Start Highly Confidential)** [redacted] **(End Highly Confidential)** does not absolve it of its responsibility to manage its system.

Q. What dollar amount of capital investment is CUB recommending taking out of this case?

A. CUB is recommending a disallowance of **(Start Highly Confidential)** [redacted] **(End Highly Confidential).**

III. CARTY AIR INTAKE FIRE

Q. Please summarize your testimony on this subject.

A. CUB recommends a disallowance associated with capital investments made to repair the power plants at Carty after an incident at the facility. Customers should be held harmless for this event that led to increased costs and was beyond their control.

Q. What is Carty?

A. Carty is a combined-cycle combustion natural gas power plant. Carty is in Morrow County, Oregon. Carty is owned and operated by PGE and is the Company's newest natural gas power plant.

Q. What happened prior to the disputed incident at Carty?

A. **(Start Highly Confidential)** [redacted] **(End Highly Confidential)**[7]

Q. What is the function of the air intake?

A. Air is a major input to natural gas electricity generator. The air intake structure is designed to filter ambient air that is drawn into the natural gas turbine.

Q. How is Carty's air intake structured?

A. Refer to CUB Exhibit 303, which **(Start Highly Confidential)** [redacted]

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[7] UE 416 – CUB/105/Gehrke.

[redacted][8] [redacted] **(End Highly Confidential)**[9]

Q. What maintenance task occurred on (Start Highly Confidential) [redacted] **(End Highly Confidential)?**

A. (Start Highly Confidential) [redacted][10] [redacted] **(End Highly Confidential)**

Q. What happened to the (Start Highly Confidential) [redacted] **(End Highly Confidential)?**

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[8] UE 416 – CUB/105/Gehrke/5.
[9] UE 416 – CUB/304.
[10] UE 416 – CUB/105/Gehrke/5.

A. **(Start Highly Confidential)** [redacted] **(End Highly Confidential)**

Q. What was the root cause of the incident?

A. According to PGE documents, the root cause of this incident (**Start Highly Confidential)** [redacted] **(End Highly Confidential)**

Q. Why is CUB recommending the disallowance of costs associated with this incident?

A. The repair costs associated with this incident would not have occurred if PGE had acted differently.

The core of CUB's argument is **(Start Highly Confidential)** [redacted]

[redacted]

(End Highly Confidential) CUB recommends a disallowance of costs associated with repairs related to this incident.

Q. What is the amount in rates that CUB is seeking a disallowance of?

A. CUB is recommending **(Start Confidential)** [redacted] **(End Confidential)** in net plant associated with this incidental be disallowed.[11]

IV. AMAZON PAY

Q. Please summarize your testimony on this subject.

A. CUB recommends that PGE no longer offer Amazon Pay as a payment option to residential customers.

Q. What payment options does PGE provide to customers?

A. The Company offers the following payment options:

1. Automated Clearing House Payments
2. Physical Check
3. Bank Card (Debit or Credit Card)
4. Paypal
5. Amazon Pay

Q. Are there costs associated with these bill payment options?

[11] UE 416 – CUB/305.

A. Yes. There are incremental payment processing costs with each of these payment options. The cost varies from **(Start Confidential)** [redacted] **(End Confidential)** for ACH to **(Start Confidential)** [redacted] **(End Confidential)** for Amazon Pay. Amazon Pay **(Start Confidential)** [redacted] **(End Confidential)** [12] Other payment options **(Start Confidential)** [redacted] **(End Confidential)** The cost of bill payment options is forecasted in each general rate case and are socialized to all customers classes.

Q. What is the Amazon Pay option?

A. The Amazon pay option is a digital wallet option. Unlike other payment options, digital wallets allow customers to pay for their utility bill without having to input payment information. Instead, the customers log into their Amazon account, and Amazon uses payment information stored on the Amazon account to draw funds to pay the utility bill.

Q. What is CUB's concern with Amazon Pay bill payment option?

A. There is no evidence that offering the Amazon Pay payment option is necessary, especially in light of the relatively high transaction costs residential customers incur when using this option. While CUB acknowledges that there are advantages to customers paying their utility bill with a digital wallet payment option, PGE

[12] UE 416 – CUB/306.

allows customers to pay for their bill with digital payment options such as PayPal or Fee Free Bank Cards.

PGE has not justified the **(Start Confidential)** [redacted] **(End Confidential)** compared to other payment options. It is CUB's position that **(Start Confidential)** [redacted] **(End Confidential)** option compared to other payment options that avoid that inefficiencies and increased costs renders it unnecessary.

Q. Why is CUB recommending that the Company no longer offer Amazon Pay to residential customers right now?

A. PGE had fewer than 600 residential customers using Amazon Pay as of December 2022. As this bill payment option grows in enrollment, it will be more difficult to transition customers away from this bill payment option. It is better for customers to end this payment option now, **(Start Confidential)** [redacted] **(End Confidential)**

Q. Has the Company discontinued offering a bill payment option in the past?

A. Yes. In UE 394, the Company agreed to only allow non-residential customers to use fee free bank cards on payments up to $1,500.

Q. Is there a revenue requirement impact associated with adjustment?

A. Yes. Given current adaptation levels of the bill payment option, the impact of adjusting Amazon Payment is de minimis. However, CUB still makes this recommendation because the annual cost to all customers associated with the Amazon Pay option will grow over time.

V. EMPLOYEE DISCOUNT

Q. Please summarize your testimony on this subject.

A. CUB recommends that the Commission reduce the residential service discount in rates for PGE employees to 5%. PGE currently offers a 25% discount to employees that is included in the rates PGE's customers pay. It is inappropriate and inequitable to provide a higher discount to PGE employees than to low-income customers.

Q. What is PGE's employee discount program?

A. PGE provides a 25% discount on residential service to its employees. In this proceeding, the Company is requesting to recover the costs of this 25% discount.

Q. What was PGE's initial request in rates for employee discounts?

A. PGE initially requested to include $1.502 million in rates for employee discounts for their customers for 2024. During the discovery process, CUB and PGE discovered that 2019 employee data was used to calculate employee discounts. The Company has indicated that it plans on using updated employee information for calendar year 2022 in its next round of testimony.[13] Using 2022 information, CUB estimates that PGE's initial request proposes to collect $1.642 million from customers.

Q. What is the low-income discount program?

[13] UE 416 – CUB/307.

A. PGE offers a low-income discount program to eligible customers. There are three tiers of low-income customers discount levels. The first tier (household income up to 31% of Oregon State Median Income (SMI)) receives a 25% discount. The second tier (household income between 31% and 45% of Oregon SMI) receives a 20% discount. The third tier (household income between 46% and 60% of Oregon SMI) receives a 15% discount. As currently structured, PGE's employees would receive the same discount as the first tier of eligible low-income customers. It is highly unlikely that any of PGE's employees would be eligible to participate in this program, yet they receive the same discount, which is paid for by all customers—including low-income customers.

Q. What is the difference between the low-income program discount and employee discount program?

A. The Company provides a flat employee discount to PGE employees of 25%. The average PGE employee is well compensated with an average salary of **(Start Confidential)** [redacted] **(End Confidential).**[14] For decades, low-income households have not been offered discount programs to mitigate their energy burden, while employees of the Company have been enjoyed substantial discounts as a fringe benefit.

Q. Why is CUB proposing to reduce the employee discount percentage included in customers' rates?

A. CUB acknowledges that the PGE employee discount has been a long-standing discount program. However, it is unreasonable to ask customers to offer a larger

[14] This average salary number of PGE employees is for positions filled as of 12/31/2022.

discount for PGE's employees of the Company than for low-income households. If the current policy were allowed to continue, PGE's employees would receive a larger discount on electricity service than residential households between 31% to 60% of Oregon SMI.

Q. Has CUB found evidence that the employee discount is a major benefit that allows PGE to attract employees to work for the Company?

A. No. Not all of PGE's employees even qualify for the employee discount. Some of PGE's employees live outside of their service territory, and despite not qualifying the discount, these employees have kept employment at PGE.

Q. The Company may argue that this level of discount is needed to attract and retain labor from other competitors that offer an energy discount. What is CUB's response to that statement?

A. CUB disagrees with that argument. Peer utility Bonneville Power Administration has been able to attract and retain employees without offering an employee discount on utility service. If the Commission were to adopt CUB's proposal, CUB would propose that peer investor-owned energy utilities in Oregon similarly reduce the employee discounts they offer. CUB would make this proposal in the appropriate general rate case venue for PGE's peer energy utilities.

Q. What is CUB's proposal?

A. CUB proposes that employees discount be reduced to 5% for PGE's employees.

Q. What is the impact of this adjustment?

A. The adjustment provides a 1.314 million reduction to PGE's revenue request in this case.[15] However, this number is subject to the final price change for residential service.

VI. RATE DESIGN – RESIDENTIAL BASIC CHARGE

Q. Please summarize your testimony on this subject.

A. CUB supports PGE's proposal to increase the basic charge as detailed its initial filing. PGE has proposed to increase the residential customer charge for residential for single family from $11 to $13, and from $8 to $10 for multifamily.

Q. Why does CUB support PGE's rate design change for the basic charge?

A. CUB finds PGE's rate design change to be reasonable. In the last general rate case, PGE's total basic charge revenue decreased on the residential class level. While CUB is concerned by the impact of increasing the customer charge on the bills of low usage customers, this concern was partially mitigated by differentiating the basic charges for multi-family and single-family customers. On balance, CUB finds PGE's rate design proposal on the basic charge to be reasonable.

Q. Does CUB's support in this proceeding for the basic charge signal support for increasing the customer charge in future general rate cases for energy utilities?

A. No. CUB's position is specific to the circumstances of Portland General Electric's 2023 general rate case and is the result of our review of the revenue collected from the various residential basic charges.

VII. RATE DESIGN – SCHEDULE 7 INVERTED BLOCK RATES

[15] This calculation is based on 2022 employee kWh and accounts.

Q. Please summarize your testimony on this subject.

A. CUB supports eliminating inverted block rates for residential customers.

Q. What are inverted block or tier rates?

A. Inverted tier rates are a pricing structure where the pricing for electricity increases the more a customer consumes. Schedule 7's energy charge has been structured as an inverted tier rate. Historically, monthly energy usage for residential customers under 1000 kWh has been priced at a lesser amount than energy usage above 1000 kWh.

Q. Has PGE's Schedule 7 been gradually transitioning to flat energy rates?

A. Yes. The rate schedule has been gradually transitioning to flat energy rates over the past few rate cases. In UE 335, inverted block rates were removed from the BPA residential exchange energy credits. In UE 394, the incremental cost between rate tiers has been reduced from $0.0072 to $0.0036.

Q. Why is CUB open to moving away from inverted tier rates?

A. In CUB's experience, residential customers have low awareness of inverted tier rates. Therefore, CUB finds the impact of the pricing signal to be diminished given customer awareness of inverted block rates. In opening testimony, PGE presented convincing evidence that low-income customers are more likely than non-low-income customers to exceed the 1,000 kWh per bill cap during heating months.

Q. Is CUB's recommendation final?

A. No. CUB finds PGE's recommendation to flatten Schedule 7 rates to be reasonable at this time given the evidence analyzed presented by the Company. However, CUB will review other parties' positions and is open to alternative methods to approaching this issue.

VIII. RATE DESIGN – TIME-OF-DAY RATES

Q. Please summarize your testimony on this subject.

A. PGE has proposed to extend the on-peak window for Time-of-Day (TOD) rates an additional hour from 5-9PM to 4-9PM. CUB opposes the Company's proposal.

Q. What is the TOD pricing option for residential customers?

A. The TOD pricing option is a voluntary tariff pricing option for residential customers where pricing for electricity varies by the time of electricity use. Under the current tariff, on-peak pricing periods occur from 5 PM - 9 PM on weekdays, mid-peak pricing occurs from 7 AM - 5 PM on weekdays, and off-peak pricing occurs from 9PM - 7AM on weekdays and on the weekend/holidays. TOD customers pay a higher unit price to consume electricity during peak periods when electricity was most costly to supply and a lower unit price during off-peak periods. The goal of this pricing program is to incentivize residential customers to not use electricity during expensive hours to manage system costs.

Q. What was PGE's proposal around TOD rates?

A. Portland General Electric has proposed to extend the on-peak period for TOD rates from 5-9PM to 4-9PM.

Q. Why did PGE make this proposal?

A. PGE made this proposal to mitigate the increase from present rates to proposed rates for the on-peak period for TOD customers. The Company has also indicated that 4PM to 5PM hour (hour ending 17) has the fourth highest marginal power costs and is in the top 25 percent of resource constrained hours for PGE's system.[16]

Q. What is CUB's response to PGE's concern?

A. The impact of any revenue requirement reductions that accrue throughout or at the conclusion of this proceeding makes it unlikely that PGE will be able to justify its initial pricing proposal. Any reduction in overall residential rates will moderate the need for any increase in the on-peak price for residential TOD customers.

CUB recognizes that there is also a balance between matching the rate schedule to cost and trying to attract residential customers to participate in these voluntary programs. CUB prefers a short on-peak window because it is easier for a customer to manage their load off-peak. This is likely to lead to greater customer enrollment, which increases the value of the TOD program to PGE's system. Additionally, CUB would like to avoid making changes to the TOD structure before a comprehensive third-party evaluation of the pricing structure has occurred.[17] For this reason, CUB recommends that the TOD rate structure remain unchanged.

Q. What is CUB's proposal?

A. CUB Exhibit 309 provides a recalculation of TOD rates, using the Company's initial proposal as a placeholder.

IX. RATE DESIGN – TOU RATES

Q. Please summarize your testimony on this subject.

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[16] UE 416 – CUB/308.
[17] UE 416 – PGE/1300/Macfarlane – Pleasant/43.

A. In this proceeding, PGE has proposed to phase out offering Legacy Time of Use (TOU) on December 31, 2024. CUB supports retiring the Legacy TOU rate option. CUB also proposes alternative ratemaking to handle the ratemaking associated with TOU no longer being offered as a rate option.

Q. What is the TOU Schedule 7 tariff option?

A. The TOU rate option is a seasonally differentiated time of use pricing schedule for residential. The TOU rate option has seasonally differentiated on, mid, and off-peak pricing periods. This rate schedule has been in place since 2002.

Q. What is the Company's proposal around TOU?

A. The Company has proposed to retire the Time of Use option on December 31, 2024.[18] When the Company proposed the TOD pricing option in 2021, TOD was designed to replace the TOU pricing option.

Q. What is CUB's position on PGE's proposal to terminate the Legacy TOU option?

A. CUB supports the Company's recommendation. The Legacy TOU program is a complicated rate option with seasonally differentiated pricing periods, and long on-peak periods. In 2018, Cadmus evaluated several time differentiated pricing programs for residential customers and found that PGE residential customers under a long on-peak window were dissatisfied with the pricing structure and found it difficult to shift load off-peak.[19] CUB agrees with the Company that would simplify marketing the program to residential customers to only have only one-time differentiated rate option.

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[18] UE 416 – PGE/1300/Macfarlane – Pleasant/42, lines 10-16.
[19] UM 1708 Cadmus Evaluation of PGE's Residential Pricing Pilot – 2018.

Q. What was the Company's plan to transition TOU customers away from that rate option?

A. The Company plans, upon receiving approval for terminating the Legacy TOU, to notify customers to contact PGE's customer service team to discuss energy plan options.[20] TOU customers will have the option to either sign up for service under residential default service or residential TOD pricing. If a residential customer does not transition away from TOU service by December 31, 2024, then that customer would be transitioned to default residential service on January 1, 2025. CUB finds the plan to be reasonable. Is it important that residential customers be notified of this transition and given the opportunity to make an informed decision.

Q. Is it necessary to keep TOU rates on the tariff book to enable transportation electrification-specific rates?

A. No. It is not a requirement to have the legacy TOU on the tariff books to have a transportation electrification specific rate. If the legacy TOU option was suspended as is proposed, then TOD pricing structure does provide an incentive for residential customers to charge off-peak.

Q. What is the Company's proposal around the ratemaking of TOU rates?

A. The Company has included a charge to residential customers to cover the revenue shortfall of TOU compared to standard Schedule 7 rates.[21] The Company has included estimated that the cost of this charge to be $382,000. The Company proposes to place this cost into base rates.

Q. Does CUB have a concern with the ratemaking around TOU rates?

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[20] UE 416 – CUB/310.
[21] UE 416 – PGE/1300/Macfarlane – Pleasant/17, lines 17-18.

A. Yes. CUB is concerned that including this amount in base rates and being subject to regulatory lag is unreasonable because this rate schedule may be terminated at the end of the test year. CUB recommends that the dollars associated with this charge be reversed once TOU is transitioned away from being offered.

Q. Why is this reasonable?

A. For the TOD rates, PGE has been able to track the revenue difference between standard Schedule 7 and TOD customers through Schedule 105 while the program increases enrollment and matures. The Company has been allowed to recover revenue costs associated with a growing TOD outside of traditional ratemaking. It is symmetrical to provide the same benefit to customers when the TOU rates are being phased out.

Q. How does CUB propose to credit that value back to customers?

A. CUB proposes that the value in residential customers-based rates for revenue lost due to TOU be credited back to residential customers through Schedule 105 on January 1, 2025 once TOU is terminated, until rates are reset in PGE's next general rate case.

X. RATE SPREAD - SCHEDULE 118 AND SCHEDULE 115

Q. Please summarize your testimony on this topic.

A. CUB recommends that Schedule 118 be modified to remove the $1,000 cap for large customers. For both Schedules 118 and 115, CUB recommends that residential customers per bill rate design be calculated based on average usage.

Q. What is Schedule 118?

A. Schedule 118 is an automatic adjustment clause that tracks costs associated with PGE's Income-Qualified Bill Discount program (Schedule 18) for recovery by the Company. The discount program was enabled by House Bill 2475 (2021). PGE's shareholders do not fund the low-income discount program. Instead, the program is funded by other PGE ratepayers.

Q. How is Schedule 118's rate structured?

A. From a rate perspective, the cost of the program to non-participating, non-residential is calculated based on a per kWh rate for non-residential customers. Unlike non-residential customers, residential customers are charged this rate schedule on per bill basis. In 2023, each residential customer's monthly Schedule 118 charge is $1.14 per bill.[22] Historically, PGE has calculated the per bill for residential customers by multiplying 1000 kWh by the per kWh rate.

Q. What is Schedule 115?

A. Schedule 115 is a rate schedule that funds state energy assistance programs. This tariff implements the low-income bill payment assistance provisions in accordance with ORS 757.698(1)(a).[23] Essentially, this tariff captures the costs associated with ratepayer-funded state energy assistance programs. The amount that is collected from ratepayers varies year-to-year. ORS 757.698(a) directs the regulated utilities to collect $20 million from Oregon customers of Pacific Power and Portland General Electric.

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[22] Portland General Electric Company First Revision of Sheet No. 118-1

[23] UE 416 – PGE/1301/Macfarlane-Pleasant/194. While PGE cites to ORS 757.612(7)(b) as authority for this program, CUB believes it exists in ORS 757.698, as amended by HB 2739 (2021).

Schedule 115 has a similar rate design to Schedule 118. Non-residential customers pay a volumetric per kWh rate for this rate schedule. Residential customers are billed monthly and are calculated by multiplying the volumetric rate by 1000. The 2023 Schedule 115 rate is $1.04 per month for residential.[24]

Q. What is the average usage for PGE's residential customers?

A. Average usage for residential customers is forecasted to be 795 kWh in 2024.[25] Therefore, the Company's assumed average usage for residential under tariff Schedule 118 and 115 is 25.7% greater than what is expected for average residential usage in 2024. For several years, residential customers have historically been overcharged under Schedule 115 and 118 because residential usage has been less than 1000 per kWh.

Q. What is CUB's proposal?

A. CUB proposes to use the forecasted 2024 test year usage number for calculating the per-bill rate for residential for Schedule 115 and Schedule 118. For several years, PGE has used 1000 kWh per month to calculate the per bill rate for residential.

Q. What is the impact of this adjustment?

A. CUB proposal more accurately captures per bill usage for residential customers. CUB's proposal lowers the annual monthly bill charge to residential rate class and increases the per kWh charge for other classes. CUB proposes that these changes occur in the next time that PGE's updates Schedule 115 and Schedule 118 for the 2024 calendar year.

Q. How is Schedule 118's rate spread structured?

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[24] Portland General Electric Company Tenth Revision of Sheet No. 115-1
[25] UE 416 – CUB/311.

A. Under the current rate spread methodology, a specific customer cannot pay more than $1,000 per bill for Schedule 118 rates.

Q. What is the impact of that rate spread?

A. This rate spread mitigates the price impact of any price increases for Schedule 118. The current methodology caps the contribution of customers receiving service under those schedules, regardless of their overall energy consumption.

Q. Are the current bill discount levels static?

A. No. The current bill discount levels are interim and may need to be increased to meet the needs of low-income customers.[26] If the discount level to low-income customers were to increase, the cost shift between industrial and other customer classes would increase. That is, other customer classes would have higher prices under Schedule 118 because the contribution of large industrial rate schedules would be capped at $1,000.

Q. Has CUB been involved in the low-income discount program development?

A. Yes. CUB has been involved in this process. CUB participated in workshops prior to the adoption of the interim low-income discount program and engaged in the Commission processes addressing these issues. CUB continues to join stakeholder update meetings hosted by the Company. PGE hosts monthly stakeholder meetings to update advocates on PGE's low-income discount program. Other advocates in the low-income discount update meetings that PGE hosts monthly have been asking for a deeper level of discount for customers at the 0-20% State Median Income (SMI) level since last fall. The level of discount provided to low-income

[26] ADV 1365 – Staff Report for the April 5, 2022 Public Meeting (Item No. RA1) at 9.

households are not static and the conversation is ongoing.

HB 2475 changed the landscape and ability for the Commission to consider various solutions for low-income customers by enabling the Commission to consider "differential energy burdens on low-income customers and other economic, social equity or environmental justice factors that affect affordability" when setting classifications of service for each utility.[27] This authority did not exist previously, and essentially enables the Commission and utilities to consider income within the context of rate design and setting. The Commission and utilities now have the statutory authority to protect these customers and help mitigate their energy burden.

Through other peer Oregon energy utilities Low Income Need Assessments (LINA), it is clear that many low-income customers are paying more than the 6% income that is typically tied to a household being energy burdened. Peer energy utilities NW Natural, Avista, and Cascade Natural Gas all completed LINA's within their Oregon service territories. Avista and Cascade Natural Gas calculated energy burden as 3% or above, as many of their customers use both natural gas and electricity within their homes, meaning the combination of the two would reach the 6% definition of energy burden. NW Natural's LINA states that homes across NW Natural's service territory reporting an income of less than $30,000 are likely to be energy burdened, or above that 6% of annual income dedicated to utility costs.[28] Customers with an income of less than $20,000 had an average energy burden of

[27] HB 2475 Section 2(1).
[28] NW Natural Low Income Needs Assessment. Applied Energy Group. September 2022.

9.2%. Avista's LINA reported that of 94,000 identified households, 6,400 were identified as high energy burdened and that these customers paid an average of $740 in annual natural gas bills. 2,700 of those customers fell into the very high energy burden category of paying 5% or more for their natural gas bills.[29] Customers experiencing low income are particularly impacted by increases in the cost of energy.

The low-income discount programs are an important tool to lower energy burden by directly lowering monthly energy bills for PGE's most vulnerable customers. With low-income rate mitigation programs, customers can stay more up to date on their energy expenditures, be less likely to experience disconnection, and be more able to comfortably heat and cool their homes. These programs may need to be expanded to better reach the goal of lowering energy burden for the most vulnerable communities in PGE's service territory.

Q. What is the impact of increased customer enrollment and discount level on the revenue requirement recovered under Schedule 118?

A. An increase in enrollment will increase annual costs borne under Schedule 118. An increase in the discount level for Schedule 118 will increase costs borne under Schedule 118. As this program matures, the annual cost of this program is projected to increase. PGE's discount program has already seen a higher level of enrollment than originally predicted in PGE's Year 1 proposal and have increased their projections for Year 2 enrollment as well. PGE stated in their August 25, 2022,

[29] Avista Oregon Energy Burden Assessment. Empower Dataworks. June 2022.

stakeholder meeting that the Company started with a Year 1 goal of 15% enrollment of the eligible population, or roughly 23,000 customers. In the May 19, 2022 stakeholder session, PGE estimated that the eligible customer base was approximately 150,000 customers. The Company stated in their September 22, 2022 meeting they had increased the Year 1 enrollment number to 50,000 customers after seeing higher enrollment results when reaching out to customers who had received energy assistance in 2020-2021, and when beginning to auto-enroll customers. As the Company stated in their September 22, 2022 meeting, this increased their prediction to enroll close to 110,000 customers by the end of Year 2. PGE stated in their January 23, 2023, stakeholder meeting that the expected enrollments for Year 2 are nearly 50% higher than the original ramp rate. **(Start Confidential)** [redacted] **(End Confidential)**[30] The annual cost of Schedule 118 would grow by several million if additional discount tiers are provided. Due to the $1,000 cost cap on Schedule 118, enrollment growth shifts significant costs from larger customers to smaller customers (residential and small commercial) as this program matures. PGE stated in their May 19, 2022, stakeholder meeting that the Company hoped to reach 75% eligible enrollment by 2025. **(Start Confidential)** [redacted] **(End Confidential)**

Q. Why should the Commission adopt CUB's proposal?

[30] UE 416 – CUB/312.

A. Everyone should pay for these bill discount programs and to help our low-income neighbors, this includes all customers; industrial, commercial, and residential paying their fair share for the programs. There is not a good policy reason to make this program bypassable. NW Natural, Avista and Cascade's low-income discount programs do not have a bill cap on low-income discount program. If the Commission were to adopt CUB's recommendation of lifting the cap for Schedule 118, CUB would advocate for consistency between all Oregon energy utilities around cost recovery for low income discount programs.

The cost cap for Schedule 118 that is currently in place for non-residential customers is not required by legislation, which is an issue that CUB will address in briefing.

Q. What is CUB's proposed change to Schedule 118 and Schedule 115?

A. CUB proposes the per kWh rate be non-bypassable, and that the Commission eliminate the cap for Schedule 118. CUB recommends that the Commission adopt that the bill charges for residential customers under Schedule 115 and 118 that match average residential usage.

Q. Does this conclude your testimony?

A. Yes.

ESTERSON Sarah * ODOE

Subject: Biglow Condition 37 notification - Blade Liberation

From: Lenna Cope <Lenna.Cope@pgn.com>
Sent: Thursday, February 3, 2022 10:50 AM
To: KILSDONK Duane * ODOE <Duane.KILSDONK@energy.oregon.gov>
Cc: CORNETT Todd * ODOE <Todd.CORNETT@energy.oregon.gov>
Subject: Biglow Condition 37 notification - Blade Liberation

Duane,

Per Condition 37 of the Biglow Canyon Wind Farm site certificate, this email is to notify the Department that at approximately 2:11 a.m. February 1, 2022, Turbine 71 at Biglow Canyon Wind Farm had a blade liberation. The blade was thrown from the tower and landed in a field approximately 100 yards from the tower. The blade does not appear to have struck the tower, and the other two blades do not appear to be damaged. PGE has shut down Biglow Phase I to begin the investigation into the cause of failure. There were no injuries or property damage, and the landowners have been engaged and informed.

Please advise if you have any questions or need additional information at this time. We intend to provide additional information as to the cause of the event following our investigation.

Lenna Cope
Pronouns: she/her
Senior Environmental Specialist | 503-464-2634 | 503-313-5022
portlandgeneral.com | Follow us on social @PortlandGeneral
An Oregon kind of energy.

CUB Exhibit 302 is Highly Confidential and has been served upon the Commission and each party designated to receive highly confidential information pursuant to Order 22-138.

CUB Exhibit 303 is Highly Confidential and has been served upon the Commission and each party designated to receive highly confidential information pursuant to Order 22-138.

CUB Exhibit 304 is Highly Confidential and has been served upon the Commission and each party designated to receive highly confidential information pursuant to Order 22-138.

CUB Exhibit 305 is Confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 22-039.

CUB Exhibit 306 is Confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 22-039.

April 13, 2023

To: William Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to CUB Data Request 067
Dated March 30, 2023

Request:

Refer to PGE workpaper "2024 Ratespread_Final For Filling" tab "employee".

a. Please provide source workpapers used to calculate cells C5, C6, C25, C26.
b. What percentage of residential customer accounts that receive employee discounts are classified as multi-family?
c. What percentage of the Company's employees receive a discount on their utility service from PGE?
d. What is the number of the Company's employees that receive a discount on their PGE utility service?
e. Can a Company employee receive a residential service discount on multiple residences? If yes, please provide the number of employees that receive discounts on electric service on multiple residences.

Response:

a. Attachment 067-A provides the source workpapers used to calculate cells C5, C6, C25, C26 on the "employee" tab in the 2024 Ratespread work paper. In responding to this data request PGE discovered that the "employee" tab was using employee counts and consumption from PGE's last GRC, UE 394. PGE pulled the 2022 employee counts and consumption and is providing it in our response in addition to the 2019 employee information. PGE entered the 2022 employee information into the Ratespread work papers and found the difference to be immaterial in the overall prices PGE is proposing. PGE will provide the updated employee counts and consumption to the Ratespread when it files its Reply Testimony later this summer.
b. Of the current and retired employees that receive employee discounts, 9% are classified as multi-family.
c. PGE is unable to provide a percentage of the Company's active employees who receive a discount on their utility service, as PGE retirees are also eligible for the discount and PGE's Customer Information System does not differentiate the eligible employee discount by current employee and retiree.
d. There were 3,071 current and retired[1] employees in 2022 who received a discount on their utility service from PGE.
e. No.

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[1] This includes spouses of deceased PGE employees (so long as the spouse does not remarry)

April 17, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 463
Dated April 3, 2023

Request:

Please provide evidence that proposed the 4 p.m.-9 p.m. on-peak window is more aligned with cost causation principles than the 5 p.m.-9 p.m. window. Please incorporate data on coincident peaks and market prices in your discussion.

Response:

The proposal to increase the TOD onpeak window to 4:00-9:00 PM transfers the 4:00-5:00 PM weekday hour from the midpeak window to the onpeak window. This structural adjustment improves alignment between the TOD onpeak window and the window in which PGE calls residential Peak Time Rebate (PTR) and Smart Thermostat events, 3:00-8:00 PM, sending a clearer message to customers about high-cost hours.

The following illustrative figure reflects the reasonableness of PGE's proposal. The two shaded rows indicate the relative portion of modeled resource constraints[1] and modeled marginal power costs[2]. The 4:00-5:00 PM hour (hour ending 17) has the fourth highest marginal power costs, slightly above the 8:00-9:00 PM hour (hour ending 21) and is identified as one of top 25 percent of resource constrained hours.

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Resource Constraints																								
Marginal Power Costs																								

[1] Sourced from PGE's draft 2026 loss of load probability 12x24 heatmap
[2] Sourced from PGE's draft 2024 MONET model

Average Revenue per Customer from Schedule 7 Standard Customer

	Std Price	Units	Revenue
Energy	81.61	mills/kWh	$64.96
Transmission	7.85	mills/kWh	$6.25
Distribution	69.78	mills/kWh	$55.54
Total	159.24		$126.75
Average Monthly Use (kWh)	796		

Schedule 7 TOD Tariff Prices (cents/kWh)

	Energy	Transmission	Distribution	Combined
Onpeak	19.740	2.520	22.350	44.610
Midpeak	7.380	0.810	7.150	15.340
Offpeak	5.380	0.300	2.640	8.320

Schedule 7 TOD Prices Design

	Res Std Rate Monthly kWh per Window	Generation Price mills/kWh	Generation Adjustments mills/kWh	Generation Price mills/kWh	Generation Revenue ($)	Trans Price mills/kWh	Trans Revenue ($)	Dist Price mills/kWh	Dist Revenue ($)	Comb. Price mills/kWh	Comb. Price cents/kWh	Combined Revenue ($)
Onpeak (Mon-Fri, 5-9p)	121	145.40	52.00	197.40	23.89	25.20	3.05	223.50	27.04	446.10	44.610	53.98
Midpeak (Mon-Fri, 7a-5p)	236	82.26	-8.50	73.80	17.42	8.10	1.91	71.50	16.87	153.40	15.340	36.20
Offpeak (9p-7a & Sat/Sun/Hols)	440	63.63	-9.80	53.80	23.67	3.00	1.32	26.40	11.62	83.20	8.320	36.61
Revenue from TOD Price Opiton >>>					64.97		6.28		55.53			126.79
Revenue from Standard Price Plan >>>					64.96		6.25		55.54			126.75

Usage and Cost Allocation Inputs

	Onpeak Mon-Fri, 5-9p	Midpeak Mon-Fri, 7a-5p	Offpeak 9p-7a & Sat/Sun/Hols
Portion of unmet load hours from 2026 LOLP (draft)	48.7%	30.4%	20.9%
Residential Usage from Load Research (2019-2021)	15.2%	29.6%	55.3%
TOD Participant Usage from Billing Data (2021-2022)*	13.9%	28.3%	57.8%

*Not used in price development; included for comparison

Cost Distributions

	Desgined Generation Revenue Dist.	Actual Generation Revenue Dist	Desgined Transmission Revenue Dist.	Actual Transmission Revenue Dist.	Desgined Distribution Revenue Dist.	Actual Distribution Revenue Dist.
Onpeak	27.1%	36.8%	48.7%	48.8%	48.7%	48.7%
Midpeak	29.9%	26.8%	30.4%	30.6%	30.4%	30.4%
Offpeak	43.1%	36.4%	20.9%	21.1%	20.9%	20.9%

	Marginal Cost of Generation	
	Capacity 35%	Energy 65%
Onpeak	48.7%	15.2%
Midpeak	30.4%	29.6%
Offpeak	20.9%	55.3%

March 31, 2023

To: William Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to CUB Data Request 041
Dated March 17, 2023

Request:

Refer to UE 416 / PGE / 1300 / Macfarlane – Pleasant / 45 / Lines 1 – 2, the Company states "PGE requests approval from the Commission in this GRC to close the Legacy TOU rate to new enrollments and retire the rate at the end of 2024."

a. Please provide a narrative explanation on how the Company would transition residential customers away from the Legacy TOU rate.
b. If the Company's proposal to suspend the Legacy TOU rate is approved, would Legacy TOU customers be automatically transitioned to the standard Schedule 7 rate or to the TOD rate?
c. How does the Company plan on communicating with customers on the Legacy TOU rate if the program is suspended?

Response:

a. Upon Commission approval to suspend new enrollments and later retire the Legacy TOU option, PGE would notify active TOU customers about the planned retirement and provide information about alternative rate options. Communications would begin shortly following approval and include follow-up notifications to provide customers sufficient notice of the upcoming rate change. In the communications, customers would be directed to call PGE's customers service team to further discuss energy plan options and switch their plan to PGE's Schedule 7 default service (flat rate) or Schedule 7 Time of Day. This would be the only action necessary for the customer and their new rate would take effect following their selected alternative.
b. If the customer does not select an alternative energy plan prior to December 31, 2024, PGE will transition those accounts to Schedule 7 default service rate, effective January 1, 2025.
c. Multiple communications will be provided to customers, through their preferred method (email, text, postal service). These communications will include key dates, alternative energy plan options and other information to help the customer make the most suitable decision based on their recent energy use. Communications would begin soon after a Commission order is issued and would continue on a regular cadence until the customer selected an alternative energy plan or is moved to Schedule 7 default service at the end of 2024.

March 16, 2023

To: William Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to CUB Data Request 013
Dated March 2, 2023

Request:

It is CUB's understanding that 780 kWh is the average monthly usage figure for residential customers. Please confirm that it is the average monthly usage for residential customers. If that is not correct, please provide the average monthly energy usage for Schedule 7 customers

Response:

The average monthly energy usage for residential customers is forecasted to be 795 kWh for UE 416 target year 2024. This value is calculated by dividing the total forecasted kWh for residential customers by the forecasted number of residential bills in 2024, rounded to the nearest 5 kWh. The average monthly energy usage for residential customers forecasted for rate development in UE 394 was 780 kWh.

CUB Exhibit 312 is confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 22-039.