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August 22nd, 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 Rebuttal Testimony of Bob Jenks and Will Gehrke on Behalf of Oregon Citizens' Utility Board

To Whom It May Concern:

Please find enclosed the Rebuttal Testimony and Exhibits of Bob Jenks and Will Gehrke in Docket No. UG 416 in the above-referenced docket.

Please note that CUB's testimony and exhibits contain protected information that is being handled in accordance with General Modified Protective Order No. 23-039. The confidential portions of CUB's filing have been encrypted with 7-zip software and are being transmitted electronically to the Commission and qualified persons.

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
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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	)
	)
	)

REDACTED REBUTTAL TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

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In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision; and 2024 Annual Power Cost Update	))))))))	REDACTED REBUTTAL TESTIMONY OF THE OREGON CITIZENS' UTILITY BOARD

I. INTRODUCTION

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

A. My name is Bob Jenks. I am the Executive Director of 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 Portland General Electric Company's (PGE or the Company) Reply Testimony on some of the issues in this proceeding.

Specifically, I will discuss the following**:**

II. PGE's Power Cost Adjustment Mechanism (PCAM)
III. Single-Issue Ratemaking
IV. Schedule 122 (Associated Energy Storage in RAC)
V. Separating Deferrals and AACs

VI. Decoupling

II. POWER COST ADJUSTMENT MECHANISM

Q. Please summarize your recommendation.

A. CUB continues to recommend 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 ensure that the Company's earnings are within a reasonable range. We should not be changing from forecasted prices when earnings are reasonable.

Deadband: The Commission stated in a number of proceedings that the deadband 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 deadband. CUB believes we should return to a deadband based on basis points of ROE. The current deadband has shrunk from 150/75 basis points to an amount that is closer to 50/25 basis points. CUB proposes splitting the difference by setting a deadband of 100/50 basis points.

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

Q. How did PGE respond to CUB's Opening Testimony?

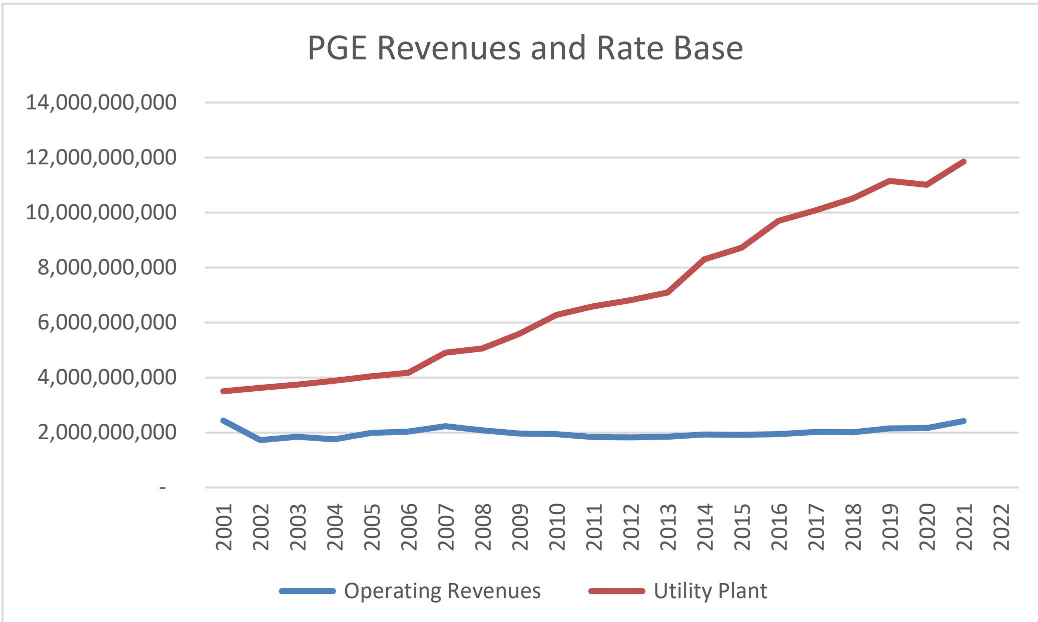
A. PGE's response included two primary elements. First, PGE makes many of the same arguments that it has made in other cases, such as that Oregon's PCAM is an outlier versus other peer utilities. Second, PGE argues that the transition to clean energy creates a need to change the mechanism. While it continues to put forth many of the same failed arguments it has used in different proceedings, it is worth noting that PGE did not challenge a significant part of CUB's testimony and in some cases expressly agreed with CUB.

Q. What facts and arguments did CUB make that PGE did not challenge?

A. There are several arguments that CUB made that PGE did not challenge and some that the Company even agrees with us on. CUB details these arguments below.

1. ***Capital investment, rate base and equity have increased significantly over the last 20 years.***

Figure 1.



As PGE's rate base (utility plant) has increased, so has the number of shareholders and the stock price. Figure 1 above and Figure 2 below demonstrate these trends.

Figure 2

	outstanding shares[1]	stock price[2]	equity (shares X price)	Impact on equity of $30 million deadband
2000	42,758,877.00		-	
2007	65,500,000.00	26.7	1,748,850,000.00	1.72%
2014	78,180,000.00	36.71	2,869,987,800.00	1.05%
2022	89,283,353.00	49.71	4,438,275,477.63	0.68%

[1] *See* PGE 2022 and 2015 Annual Report 2022 and PGE 2007 and 2001 10-K.
[2] *See* Yahoo Finance, December 1 opening stock price, Dember 1 2022, 2014, and 2007.

Since 2000, PGE has more than doubled the number of outstanding shares of stock it has issued. While its stock was not independently traded while it was owned by Enron, since becoming independent, its stock price has gone from $26.70 in 2007 to $49.71 in 2022. In 2007, a $30 million deadband in the PCAM represented 1.72 percent of equity, today it represents 0.68 percent of equity. This indicates that PGE is much better suited to absorb power cost variations within the deadband today than ever before.

2. ***The share of PGE's revenue requirement that represents net power costs has declined.***

This makes a lot of sense, as the utility continues to replace fossil fuel plants with renewables, it no longer has to purchase fuel and the share of its overall revenue requirement that is represented by net variable power costs declines. While a gas turbine has an original capital cost, much of the lifetime cost of producing electricity from a gas turbine is its fuel cost. Conversely, the lifetime costs of a renewable facility are front loaded and consist primarily of associated capital costs. Figure 3 below represents the share of PGE's total operating revenues that have been attributed to net variable power costs over the years.

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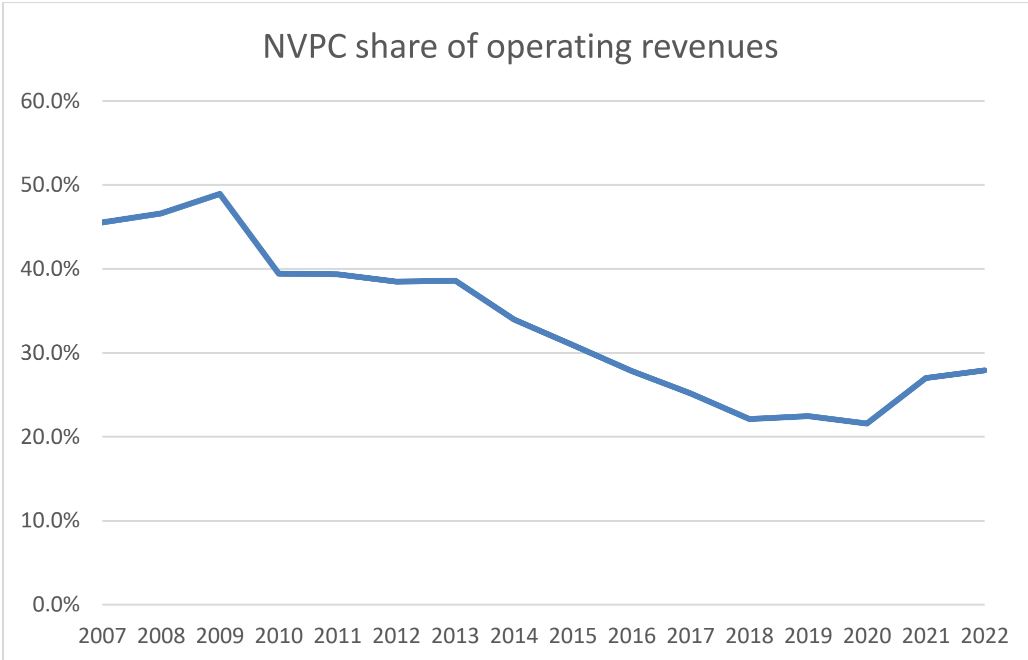
Figure 3



As PGE continues to implement state policy, the Company will procure more non-emitting energy resources. In a few years, PGE will no longer have Colstrip in its portfolio. This means that net variable power costs will no longer contain coal costs. To meet the goals of HB 2021, the amount of gas it consumes will have to decline reducing that share of power costs. Over the next two decades, fuel costs are projected to represent a continually declining percentage of the Company's revenue requirement.

3. ***PGE has been relatively good at forecasting power costs***

In Opening Testimony, CUB showed that PGE has been relatively good at forecasting power costs. In Reply Testimony, PGE says that it agrees with this. This empirical fact can be shown in the chart below:

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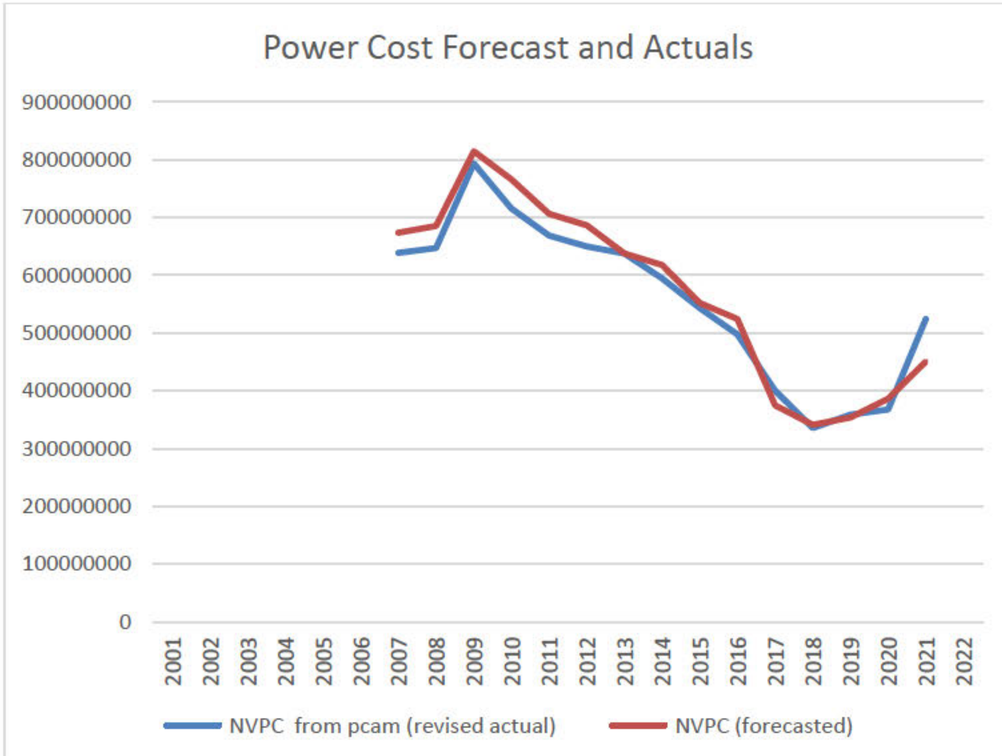
Figure 4



This accurate forecasting means that the variance is typically much smaller than the deadband and has varied in both directions. Over the last 10 years, the variance has been positive 5 times and negative 5 times. It has been under $10 million 4 times, and $15 million or less 8 times. Only once in the last 10 years has the variance exceeded the deadband. Despite this accuracy PGE seeks to eviscerate the PCAM. Power cost variances over the years can be seen in the following table.

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Table 1

	Deadband Variance (in millions)[3]
2013	$11
2014	($7)
2015	($3)
2016	($10)
2017	$15
2018	($3)
2019	$5
2020	($13)
2021	$30
2022	$23

It is worth noting that the accuracy of PGE's forecasts and the lack of deviation from the deadband creates regulatory efficiency. For example, there was not a need in 2020 to review 2019 actual power costs to determine whether the $5 million additional cost was related to imprudent actions by the utility. In most years, only the forecast requires significant regulatory review. This administrative efficiency benefits both the Company and intervenors.

Q. How do you respond to PGE's claims regarding their risk versus peer utilities?

A. One of PGE's long-standing arguments against the PCAM is that it requires PGE to take more risk than their peer utilities. PGE made this argument extensively in UE 215 and UE 180/181/184. It has been rejected by the Commission as a basis to change the design of the PCAM.

[3] *See* CUB Exhibit 401.

PGE expanded on this argument in this filing by claiming that CUB inherently agrees with the claim, which we do not:

> CUB inherently recognizes that customers in PGE's service territory shoulder less risk than customers elsewhere, and, therefore, PGE shoulders more risk than our peer utilities.[4]

CUB did not testify that customers in PGE's service territory shoulder less risk than customers elsewhere. PGE has not demonstrated it in this case. Evaluating the risk of a utility is a holistic exercise. There are a lot of elements that contribute to risk.

Regulatory lag on large capital investments is one of the biggest risks that utilities incur. With the single exception of Faraday, PGE has not absorbed regulatory lag on any major generation investment going back to Coyote Springs in the early 1990s. It avoided it for Carty,[5] Tucannon,[6] Port Westward 1,[7] Port Westward 2,[8] and Coyote Springs.[9] PGE currently utilizes the Renewable Resources Automatic Adjustment Clause (RAC) for new renewable resources. For non-renewable resources, PGE has always brought rate cases that end a little before the new generating assets are online so the Company can argue to have it rolled into the rates that are established on its first day of the plant's operation. They tried to do it with Faraday but the project was delayed too long. The elimination of regulatory lag is a very significant risk reduction that the Company enjoys while many of its peer utilities do not.

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[4] UE 416 – PGE/2400/Villadsen – Liddle/3.
[5] *See* UE 294 – CUB/100/Jenks – McGovern/2.
[6] *See* UE 283 – PGE/400/Pope – Lobdell/16.
[7] *See* UE 283 – PGE/400/Pope – Lobdell/21.
[8] *See* UE 180 – CUB/200/Jenks – Brown/2.
[9] *See* UE 294 – CUB/100/Jenks – McGovern/2.

Single-issue ratemaking reduces PGE's risk of cost recovery. The proliferation of single-issue ratemaking in Oregon reduces company risk. While CUB is arguing that there should be sunsets and earnings tests applied to these mechanisms, CUB has supported single issue ratemaking mechanisms when they are applied appropriately. CUB supports cost recovery for utilities. In a recent presentation to investors, PGE cites to the RAC as part of the "regulatory dynamics" that "support PGE and the transition to clean energy."[10] PGE recognizes that these mechanisms reduce its overall risk profile both internally and relative to peer utilities.

Forward looking test years are used to set rates in Oregon, rather than historic test years. This reduces the risk to the utility because it allows it to look forward and anticipate expenses to include in rates. This is a significant risk reduction and is cited by the utility in its investor presentation as part of Oregon's "constructive" regulatory environment.[11]

A single state utility like PGE avoids the risk that when different states disagree on cost allocation, it can leave the utility with a hole in its revenue requirement. PGE is a single-state utility, which inherently reduces its regulatory risk. Multi-state utilities have the risk that its states do not agree on regulatory cost allocation. PacifiCorp, for example, has had to accept that the State of Washington views cost allocation different than other states and the result is that the sum of the cost of

[10] CUB Exhibit 401.
[11] *See* CUB Exhibit 401.

plant and equipment allocated to each state is less than the total cost of all plant and equipment of the Company. When the Centralia coal plant was sold, the various states that PacifiCorp serves claimed more than 100% of the gain on the sell because some based their state's share on current allocation of the plant and some states based their share on the historic contribution to the plant's capital cost.[12]

While Oregon has long used a PCAM that recognizes that it is reasonable to assign level of normal business risk to the utility, this does not inherently mean that Oregon utilities carry more risk than their peers in other states. Oregon has many approaches to regulatory policy that reduce and minimize risk to the utility. PGE's focus on PCAM risk, even as net power costs are declining as a share of revenue requirement, does not demonstrate that the utility is riskier than its peers. Ultimately, PGE has been able to attract the investors necessary to invest billions of dollars in rate base associated with the clean energy transitions for more than two decades while the Commission policy has required sharing of excess power costs. PGE has offered no evidence in this proceeding that the PCAM has somehow precluded it from accessing necessary capital markets due to its perceived increase in risk.

Q. How do you respond to PGE's argument that the transition to clean energy requires a change to the PCAM?

A. Again, while the Company cites to HB 2021 specifically to argue to change the PCAM is new, the basic argument is not. In 2013, PGE and PacifiCorp filed a

[12] https//www.deseret.com/2000/4/18/19557456/Utah-agency-s-claim-stalls-sale-of-washington-power-plant

request to modify the PCAM because of the change in the business environment due to the enactment of "a renewable portfolio standard (RPS) and an emissions performance standard (EPS), both of which increase the normal business risk PGE and PacifiCorp face in serving their customers."[13] In the three years following this claim of higher risk (2014, 2015 and 2017), PGE's forecast of net power costs was above its actual power costs, so shareholders actually benefitted from the deadband.[14]

The transition to clean energy provides PGE a huge opportunity to make capital investments, which is the source of shareholder profits. PGE has signaled to investors that its earning per share growth rate guidance will increase from a range of 4% to 6% to an increased guidance of 5% to 7%.[15] This transition increases ratebase without increasing fuel costs. It is being done in an environment that is supportive of clean energy investment on both a regulatory and a legislative basis. And as discussed above, by significantly increasing PGE's rate base and equity investment, ratebase growth shrinks the impact of the deadband.

In its presentation to investors, PGE touts Oregon's transition to clean energy and the supportive regulatory environment as a good thing for investors. Under the heading "Constructive regulatory / policy environment: the company lists the following bullets:[16]

[13] *See* UM 1662, Initial Filing, at page 1. (June 19, 2013).
[14] *See* CUB Exhibit 401
[15] CUB Exhibit 402.
[16] CUB Exhibit 401.

Figure 5

Oregon

- Oregon legislation requires 100% clean energy by 2040
- Oregon Public Utility Commission
  - Governor-appointed 3-member commission with staggered 4-year terms
  - Commission has consistently approved investments in renewables, going back to Biglow Canyon Wind Farm, which went online 15 years ago
- Regulatory dynamics support PGE and the transition to clean energy
  - Renewable Portfolio standard (adopted in 2007; increased in 2016)
  - Renewable Adjustment Clause
  - Forward test years
  - Integrated resource planning framework
  - Accelerated depreciation of Colstrip to 2025
  - History of reasonable settlements in rate cases
  - Regulatory support for recovery of storm response and wildfire mitigation costs

The 100% clean energy legislation, the RPS, and the RAC are listed as constructive policy and are being promoted to investors as indicating a favorable regulatory environment in Oregon. This makes sense to CUB. These policies are creating investment opportunities for shareholders and the ratemaking mechanisms that flow from them decrease the utility's risk. The investments in clean energy will significantly increase PGE's profits. State policies which drive utility investment while eliminating regulatory lag create relatively low risk investment opportunities. PGE's assertion that the transition to clean energy is somehow increasing its risk profile is misguided.

Q. Has PGE's Reply Testimony changed CUB's thinking in relationship to the PCAM?

A. No. The arguments PGE continues to raise are not new. CUB continues to believe that it is appropriate to forecast net variable power costs and limit true-ups to circumstances where the risk to the utility is beyond traditional business risk. PGE continues to want as close to dollar-for-dollar recovery as it can get and to shift as much cost and risk as possible onto its customers. CUB's is concerned that as PGE's ratebase and equity grow, the deadband effectively shrinks, so CUB is recommending that the deadband be set in terms of basis points ROE as it originally was.

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 ensure that the Company's earnings are within a reasonable range. We should not be changing from forecasted prices when earnings are reasonable.

Deadband: The Commission stated in a number of proceedings that the deadband 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 an amount that is closer to 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.

III. SINGLE-ISSUE RATEMAKING

Q. What was PGE's response to CUB's Opening Testimony concerning single-issue ratemaking?

A. PGE dismisses most of CUB concerns. PGE does not believe that the proliferation of single-issue ratemaking mechanisms is a problem. CUB is not surprised by PGE's argument since one of PGE's goals in this docket is to increase single ratemaking by including energy storage in the RAC. However, we find much of the Company's arguments do not make sense.

Q. How do the Company's arguments not make sense?

A. PGE begins its response by saying that it finds the idea that single-issue ratemaking shifts risk to customers to be "illogical and without merit or support."[17] The Company states that including these costs in base rates "will increase the risk profile of the company."[18] PGE believes assigning this risk to customers is a benefit because it decreases "the risk that customers will pay in excess of the actual amounts spent by the company."[19] PGE's states that by "including these costs in an AAC, resulting in dollar-for-dollar recovery, both the utility and customer benefit."[20] It makes no sense to say that there is a significant forecast risk associated with costs when they are placed on shareholders but a benefit when they are placed on customers. Actual costs can be higher or lower than forecasted costs. There is inherently a business risk when prices are forecast and determined before a customer purchases a product. While the result of that forecast risk can be positive or negative, it is a risk. The issue in this case is whether this risk is assigned to shareholders, customers, or shared. Assigning it to customers through single-issue ratemaking using a true-up does not change the fact that it is a risk. The fact that in some years the party who took on the risk will benefit, does not change the fact that it is a risk—in fact, in many instances a party will take on risk because of the chance that there will be a benefit. The issue in this case is how to assign this risk.

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[17] UE 416 – PGE/2900/Ferchland – Macfarlane/3.
[18] *Id.*
[19] *Id.*
[20] *Id.*

PGE's argument that this is only a risk when assigned to shareholders makes no sense—but they make it repeatedly. Independent third parties have found that increasing the utilization of single-issue surcharges has the practical effect of shifting risks onto customers:

> the increasing imposition of surcharges and other alternative ratemaking mechanisms can also defeat some of the primary principles of the rate-setting and regulatory review process. Besides increased costs to consumers, surcharges can also result in such additional undesirable consequences as reducing utility incentives to control costs and shifting utility business risks away from investors and onto customers.[21]

When this risk is assigned to ratepayers, it creates the potential that prices for electricity might be greater than then the prudent, just and reasonable cost of providing current service because utility rates are increased by surcharges that are designed to retroactively offset utility losses in previous years.

Q. Does CUB oppose the use of single-issue ratemaking?

A. No. CUB does not inherently oppose the use of every single mechanism across PGE's system. CUB has been supportive of many of the single-issue mechanisms. However, CUB believes that there should be a regulatory preference for holistic ratemaking. Just and reasonable rates are based on a holistic view of utility costs and rates. Because single-issue ratemaking makes a holistic review more difficult, it should only be used when it there is good reason and it should be subject to controls such as earnings tests and sunsets to ensure that it is not leading to overall higher rates and that it is still necessary. The Commission's role to ensure that rates are just and reasonable overall is made more difficult by the proliferation of single-

[21] Increasing Use of Surcharges on Consumer Utility Bills, Prepared by Larkin & Associates, PLLC for AARP (May 2012) at ii *available at* https://www.aarp.org/content/dam/aarp/aarp_foundation/2012-06/increasing-use-of-surcharges-on-consumer-utility-bills-aarp.pdf.

issue ratemaking mechanisms, especially by those that do not contain an earnings test or any other consideration of rates across the Company's system.

Q. After reading PGE's response testimony, does CUB still feel that single-issue ratemaking mechanisms are overused?

A. Yes. PGE attempts to downplay the use of single-issue ratemaking by doing things like showing a chart of AACs that excludes the AUT and the PCAM – saying it will explain in briefing why those are not AACs.[22] Whether the AUT and PCAM are technically defined as AACs is not really a major concern of CUB. The AUT and the PCAM are single-issue ratemaking mechanisms. One of our concerns is that ratemaking is a holistic determination that looks at the overall result, not individual elements. As a customer of PGE, my rates are unreasonable when they are too high in comparison to all of the utility's costs, including the need to earn a reasonable return. This is not a determination that can be made when looking at a single element. CUB's concern includes AACs, and deferrals, and whatever PGE wants to call the PCAM and AUT. Our concern is single-issue ratemaking and its impact on overall ratemaking.

In addition, PGE's opening statement on single-issue ratemaking explains why it is used, then PGE goes forward and argues that it should be used outside of those areas. CUB is concerned that PGE's approach is to use single-issue ratemaking wherever it is allowed.

Q. Please explain.

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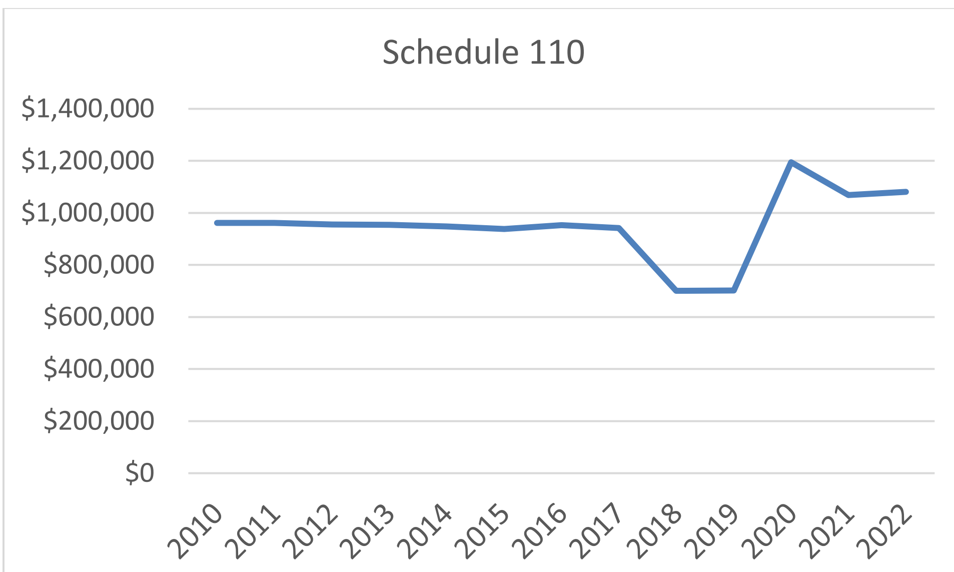
[22] UE 416 – PGE/2900/Ferchland – Macfarlane/10.

A. PGE states that AACs are "used for known but difficult to forecast costs or costs that require collection so that they may be dispersed by PGE to a government authority."[23]

In opening testimony, CUB highlighted Schedule 110, an AAC balancing account that has been used for more than a decade that is for a small, consistent cost that is internal to PGE. It is not difficult to forecast. It is not collected and turned over to a government agency. It is not even very much money. It is not clear why these costs must be recovered through a single-issue mechanism.

Figure 6



This is a cost associated with some of PGE's internal energy efficiency costs. It is one of the many adjustment schedules that shows up on PGE bills. Until the pandemic hit, it was consistently forecast at below 1 million. Today, it is a little above $1 million. On my PGE bill, it is billed at a rate of $0.00004. In opening

[23] UE 416 – PGE/2900/Ferchland – Macfarlane/3.

testimony, CUB offered this as an example of something that made little sense to retain. It does not meet PGE's description of a cost that should have an AAC, and it has been in place for more than a decade. CUB's point wasn't that this small cost was a big problem, but it is an example of an AAC that serves little purpose, but never goes away.

PGE responds that this balancing account has been in place since 2008 and it cannot be included in base rates because SB 838 requires that customers who use more than one average megawatt of electricity in the prior year shall receive a credit against this cost. PGE charges lots of customers for different items. Large customers who are eligible for direct access get assigned different costs. In this case, the law doesn't even prohibit assigning this cost to large customers, it requires that they receive a credit "against" the charge. CUB has little doubt that PGE could forecast this cost into base rates while still giving large customers who used more than 1aMW the previous year the appropriate credit. But in that case, PGE would no longer be able to use a balancing account for this cost. It would no longer get dollar-for-dollar recovery, so this continues to be a separate line item on my bill as it has since 2008.

Q. How did PGE respond to CUB's recommendations for single issue ratemaking:

A. Below, I list each of CUB's specific recommendations and PGE's response.

> ***CUB Recommendation 1***: 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**.**

PGE Response: PGE says it is willing to file an annual report on current deferrals and AACs.

Such a filing would be helpful and should be required. However, such a filing should include all single issue ratemaking mechanisms (schedules). It is not clear from PGE's response testimony whether they think Schedule 110 is an AAC. And it is clear that PGE believes that some mechanisms like the AUT and PCAM are something else. An annual report should include all of them.

CUB Recommendation 2: 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.

PGE Response: PGE responds that this is unnecessary because AACs get reviewed every 2 years.

CUB disagrees with PGE that this is unnecessary. The current review process typically has AACs quickly reviewed at a public meeting, often on the consent agenda. Those reviews are typically about the rate that the AAC will charge, not whether the AAC is still appropriate for the cost. CUB envisions a more robust process that could happen within a rate case or outside of a rate case. CUB believes that a process that requires the utility to justify why the single-issue ratemaking is necessary is needed. In some cases, such as the AUT, this may not be difficult, but in other cases it may be. Further, while the AAC statute allows for review of these mechanisms at least every two years, a significant review rarely occurs in practice. The RAC is a great example of an AAC that has not had a significnat review in many years.

CUB Recommendation 3: 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.

PGE Response: CUB does not say how a utility would prove that an earnings test is unnecessary, that this would cap utility earnings, and that it is untrue that AACs shift risk from utility to customers.

Use of earnings test is important to balance the increasing use of single-issue ratemaking with the Commission's core responsibility to set rates at an overall just and reasonable level. An earnings test allows us to determine if rates need to be adjusted to allow a cost to be recovered. PGE believes that if it fails an earnings test, then it is denied recovery of the cost, but this is incorrect. When a utility fails an earnings test it means that rates are already sufficient to allow the cost to be recovered and no further rate change is necessary. An earnings test is an attempt at taking a holistic look at rates to determine whether rates need to be adjusted. CUB believes a primary purpose of regulation is the setting of rates. Overall rates should be set at a level to allow the opportunity for a utility a reasonable return. An earnings test is simply an attempt to look to see if rates are already sufficient. An earning test can also preclude the utility for refunding money when it is underearning. CUB is not trying to cap earnings. CUB is trying to prevent rate increases from occurring when rates are already sufficient to recover PGE's costs.

As far as PGE's claim that AACs are not shifting risk to customers, this is not true. In a general rate case, PGE's costs cannot lead to the establishment of a rate that is designed to allow the Company to earn above its authorized amount. The rate that is set is the rate that is sufficient to recover all of the utility's costs plus earn a reasonable return. The fact that, without an earnings test, customers can be assigned rates that are higher than what is sufficient to recover all of the utilities costs (including costs subject to single issue ratemaking) shows that customers are taking additional risk when items are moved out of base rates and into single-issue mechanisms. One risk that customers take, is the risk that rates will be higher than they otherwise would be if traditional ratemaking was used to establish just and reasonable rates.

***CUB Recommendation 4*:** CUB recommended that schedules 110, 112, and 134 be eliminated.

PGE's Response: PGE agreed to eliminate schedule 112, and 134 but opposes eliminating Schedule 110.

CUB continues to recommend that schedule 110 should be eliminated.

CUB Recommendation 5: CUB recommended that PGE should be required to justify retaining Schedule 138 and 145 in its next general rate case.

PGE Response*:* There is a settlement relating to Schedule 145. PGE opposes justifying Schedule 138, relating to energy storage projects under HB 2193. Instead PGE pledges that 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."[24]

HB 2193 was passed in the 2015 legislature. PGE's next general rate case will likely occur at least 10 years after the bill passed. CUB continues to believe that PGE should have to justify why this AAC is still required. PGE's commitment to "review" it after all projects are completed and all pilot projects are finished is not adequate – that could be another 10 years – and PGE could review it and decide that they like it without ever having to justify it continuation. CUB believes that when the costs of this program become predictable and forecastable, it should be moved

[24] UE 416 – PGE/2900/Ferchland – Macfarlane/25.

into base rates. Requiring justification 10 years after the legislation passed is not regulatory overkill.

CUB Recommendation 6: CUB recommends that the costs associated with the RFP, IE and any third-party consultants, be placed into base rates.

PGE's Response: PGE opposes CUB's request arguing that these costs are required of the company, do not occur every year and are not under PGE's control.

After reviewing PGE's filing in UM 2274, CUB no longer pursues this proposal due to uncertainty around how PGE's RFP will occur in the medium to near term and impact independent evaluator costs. Despite CUB recognizing how the procurement process is changing, CUB does not agree with the Company's position that these costs cannot be placed into base rates in the future.

In UM 2274, PGE filed an update to its Planning and Procurement Forecast. The Company is recommending two options for resource acquisition through an RFP. The first option is conducting resource acquisition under existing competitive bidding rules, which results in two RFPs prior to 2030. The second option is for PGE to move forward with an extended RFP process, where the Company could seek evaluate and evaluate bids multiple times, subject to changes in need from the CEP/IRP.

IV. SCHEDULE 122 (ASSOCIATED ENERGY STORAGE IN RAC)

Q. What is the purpose of your testimony on this issue?

A. My testimony on this issue addresses and responds to arguments raised in PGE/2700 surrounding the treatment of energy storage resources in its Schedule 122 Renewable Resources Automatic Adjustment Clause (RAC).

Q. Please summarize your testimony.

A. In PGE/1300, the Company initially requested that the Commission clarify that standalone energy storage that is used to integrate and firm renewables on a utility's system qualifies as "associated energy storage" for purposes of inclusion in the RAC to avoid regulatory lag.[25] After apparently realizing that its overly-broad proposed definition faced an uphill battle to be adopted by the Commission, PGE now offers a slight clarification to its proposed "associated energy storage" definition. In Reply Testimony, PGE clarifies "that for purposes of the [RAC] PGE's proposed definition of 'associated energy storage' limits the standalone energy resources to those that connect at the transmission-voltage level."[26]

Despite PGE's clarification, CUB continues to disagree with the Company's broad interpretation of the word "associated," which would allow virtually 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, "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. This treatment is similar with the historic treatment of "associated transmission" projects that have been included in the RAC—no PGE transmission asset that is not physically connected to an underlying RPS eligible resource has ever been included. PGE's proposal in this

[25] UE 416 – PGE/1300/Macfarlane – Pleasant/45.
[26] UE 416 – PGE/2700/Blosser – Sheeran/4, lines 7-10.

case is likely to lead to poor policy and ratemaking outcomes and should be rejected. Further, for the first time in Reply Testimony, PGE shows its cards and demonstrates why it seeks to make this change—to avoid the potential for any regulatory lag on its Evergreen and Seaside energy storage projects.[27] Unfortunately for PGE, the Commission must determine the reasonableness of PGE's proposal based on the statutory construction of the legislative language at issue rather than the Company's regulatory desires.

Q. Has PGE been consistent on it has proposed to use the RAC for associated energy storage?

A. No. In Docket No. UE 372, The Company sought cost recovery through the RAC clause for two microgrid battery storage projects: the Beaverton Public Safety Center (BPSC) and the Anderson Readiness Center (ARC). Both of these projects are connected at the customer premise behind the meter, not at the transmission voltage level.[28] In UE 372, the Company argued that these behind the meter storage facilities qualified for the RAC.[29] In this proceeding, the Company seeks to include energy storage resources connected at the transmission-voltage level that are used to integrate and firm renewables, which would inherently not include the BPSC or ARC. The Company is not being consistent on its definition of associated energy storage and is attempting to parse SB 1547's language on a case-by-case basis in a manner that would allow it to avoid regulatory lag for the specific energy storage projects that it is anticipating bringing on its system in a given moment.

[27] UE 416 – PGE/2700/Blosser – Sheeran/2.
[28] CUB Exhibit 403.
[29] *See generally* UE 372 – PGE/100/Murtaugh – Cristea.

Q. SB 1547 broadened the RAC's cost recovery language to include "associated energy storage." Did SB 838 (SB 1547's RPS predecessor) include the ability to recover any other resources?

A. Yes. SB 838 allows costs associated with "facilities that generate electricity from renewable energy sources and for *associated electricity transmission*" to be included in the RAC.[30]

Q. If PGE's proposal for "associated energy storage" is applied to "associated electricity transmission," what would be the result?

A. Any and all transmission resources built for PGE's system could conceivably be passed through the RAC, since all transmission is used, to an extent, to integrate and firm RPS renewable energy. However, PGE clearly does not view the "associated electricity transmission" component of the RAC in a consistent manner with the interpretation of "associated energy storage" that it seeks Commission approval of in this proceeding. Since the inclusion of the language enabling the RAC in 2007's SB 838 RPS bill, PGE has never sought recovery of a transmission project that is not physically connect (i.e., gen-tied) to an underlying qualifying renewable energy resource in a RAC proceeding.[31] Despite the legislature's intentional use of the exact same word—"associated"—for both transmission and energy storage's potential inclusion in the RAC, PGE interprets these terms differently. CUB will discuss in briefing why this is inappropriate and, therefore, why PGE's proposal must be rejected.

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[30] SB 838, Sect. 13 (3) emphasis added.
[31] CUB Exhibit 404.

Q. PGE argues that co-location could not have been considered as a viable option for energy storage resources to be included in the RAC in 2016 because there were no energy storage resources on its system that were co-located with RPS-eligible resources at the time.[32] Do you find this argument persuasive?

A. No. Despite being passed in 2016, SB 1547 was a forward-looking bill that clearly anticipated changes to Oregon electric utilities' operations and resource mixes. The law requires that coal be eliminated from PGE and PacifiCorp's allocation of electricity by January 1, 2030.[33] It expanded Oregon's RPS to mandate that 50% of the electricity sold by PGE and PacifiCorp be sourced from renewable energy by 2040.[34] Forward-looking laws like SB 1547 inherently acknowledge that changes in technology may become available that change the manner in which mandates are met. Further, the legislature's use of "associated" for both transmission and energy storage was intentional and, if PGE's historic practice has been to only consider physically connected transmission resources to be eligible for inclusion in the RAC, it follows that energy storage resources must be physically connected as well.

Q. What is an example of storage that is located on-site with an RPS eligible resource?

A. The Wheatridge renewable energy facility is a clear example of such a resource. The Wheatridge facility consists of 300 MW of wind capacity, 50 MW of solar energy and 30 MW of battery storage. The Wheatridge battery is configured to be only charged only by solar at the site. The Wheatridge battery cannot be charged

[32] UE 416 – PGE/2700/Blosser – Sheeran/7.
[33] SB 1547, Sect. 1(2).
[34] SB 1547, Sect. 5(1)(h).

by the Wheatridge wind facility or grid.[35] The Wheatridge battery is associated with Wheatridge solar, which is an RPS-compliant resource. The Wheatridge battery adds value to the RPS-compliant resource (i.e., helps the RPS-compliant resource generate more RECs than it otherwise would) that it is physically attached to and is a good example of the type of energy storage resource that should be eligible for the RAC.

Q. What did the Company assert about CUB's proposal?

A. The Company stated that "CUB's proposed interpretation of the word "associated" is entirely unreasonable, as it would results in a preference for potentially inferior, yet physically co-located energy storage and neglect to include standalone storage located in a superior location to deliver grid services and integrate renewables."[36]

Q. What is CUB's response to the Company's assertion?

A. Portland General Electric can acquire any storage resource it wants. However, to provide resource acquisition for recovery in rates, the Company must demonstrate that the storage resource was prudent. CUB's proposed definition effects the timing of rate recovery for standalone storage resource, not the value of a standalone storage resource. CUB would expect that the Company would acquire the best resource on behalf of customers. It would be imprudent for the Company to let regulatory lag on standalone batteries drive PGE's resource procurement toward only procuring co-located renewables.

[35] CUB Exhibit 405.
[36] UE 416 – PGE/2700/Blosser – Sheeran/6.

Q. PGE cites to what it considers "two key phrases" within ORS 469A.120 that it believes bolster its position.[37] How do you respond?

A. CUB will appropriately respond to arguments regarding the effect of statutory language in briefing. However, it is worth noting that PGE's reliance on the language in ORS 469A.120(1) allowing recovery of "costs associated with using physical or financial assets to *integrate, firm or shape* renewable energy sources" to support its arguments around energy storage in the RAC are misguided. ORS 469A.120(1) was a provision from SB 838's original language. Therefore, the language to which PGE cites does not consider the impact of energy storage resources and their potential inclusion in the RAC because SB 838 did not include the phrase "associated energy storage." ORS 469A.120(1)'s language could not have possibly been referring to energy storage resources because these resources were not eligible for inclusion in the initial RAC in any form. It is telling that PGE makes arguments regarding the timeline of energy storage resource rollout when it believes it helps its position, but completely ignores this timeline when it finds arguments that it believes helps its position. CUB will respond to these issues and the implications of the phrases PGE references in briefing.

Q. What is your response to Staff's position that the role of the RAC and defining "associated energy storage" should be undertaken in a future proceeding?

A. CUB agrees that there may be merit in considering these issues in a broader setting. Should the Commission find that a more robust record, that would include

[37] UE 416 – PGE/2700/Blosser – Sheeran/6.

arguments by PacifiCorp and other potentially interested parties, CUB is open to addressing the issues in that forum. Given the broad range of resources that are eligible for inclusion in the RAC—even without considering energy storage resources—CUB believes that the RAC should be reexamined to determine whether allowing it to continue in its current form is in the public interest. However, CUB believes that the evidentiary record in this proceeding is sufficient for the Commission to rule on the treatment of "associated energy storage." CUB continues to respectfully recommend that the Commission adopt CUB's proposal to define "associated energy storage" as storage that is located on-site with an RPS-eligible resource that adds value to the underlying renewable resource.

V. SEPARATING DEFERRALS AND AACs

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

A. My testimony responds to PGE's continued proposal in PGE/2900 to address AACs and deferrals "as separate mechanisms to avoid confusion and reduce the administrative burden associated with redundant filings."[38] PGE appears to still request that the Commission rule that AACs established under ORS 757.210 be recognized as exceptions to the ORS 757.259 deferral standard.[39]

Q. Please summarize your testimony.

A. CUB continues to believe the Commission should not adopt the Company's proposed change to the Commission's long-standing policy requiring that a deferral accompany and underlie an AAC.

[38] UE 416 – PGE/2900/Ferchland – Macfarlane/30.
[39] UE 416 – PGE/1400/Ferchland – Batzler/1, lines 17-20.

Q. What new arguments does PGE raise in Reply Testimony regarding this issue?

A. PGE believes that AACs "inherently contain[] the ability to true up values" and therefore do not implicate retroactive ratemaking.[40] In an effort to corroborate this statement, PGE argues that the Federal Energy Regulatory Commission (FERC) has taken the position that:

> [a] rate that may be subject to an after-the-fact public true up [sic] proceeding and/or later refund is a rate that is not subject to a prior hearing; a rate that adjust only subject to after-the-fact review, and not prior review, is a rate that can and should be legitimately considered an automatic adjustment clause.[41]

According to PGE, this statement indicates that "FERC is clear that an AAC is a single mechanism inclusive of a true up."[42]

Q. Does CUB agree with this statement?

A. No. CUB will appropriately address the Commission's long-standing prohibition against retroactive ratemaking in briefing, which will include an analysis of the Commission's historic treatment of AACs, deferrals, and the statutory underpinnings of the two discrete mechanisms. However, for purposes of this testimony, CUB submits that PGE is parsing the non-binding guidance from FERC in an incorrect manner in an attempt to further its position.

Q. Please explain.

A. In the FERC guidance document cited by PGE, the Company clings to the words "true-up proceeding" to argue that AACs include a true-up. This notion is incorrect

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[40] UE 416 – PGE/2900/Ferchland – Macfarlane/32.
[41] *Id*. at 33 citing https://www.ferc.gov/sites/default/files/2020-08/Form-580-FAQ.pdf.
[42] UE 416 – PGE/2900/Ferchland – Macfarlane/33.

for two reasons. First, the FERC document PGE relies on is actually referencing two different types of processes. In the first part of the quote above, FERC says that "[a] rate that may be subject to an after-the-fact public true-up proceeding and or later refund is a rate that is not subject to prior hearing."[43] FERC does not say that these rates—those subject to an after-the-fact public true-up—are AACs. Merely that they are a "rate that is not subject to prior hearing."[44] Further, FERC indicates that these types of rates may be "subject to an after-the-fact true-up *proceeding*."[45] CUB submits that the intentional use of the word "proceeding" here indicates that this after-the-fact true-up may be a different process altogether. This is telling, because a deferral remains the only statutory exception to the prohibition against retroactive ratemaking. The deferral that tracks the actual costs compared to those that are forecasted is the proceeding within which a true-up may or may not occur.

Second, in the latter half of the quote PGE relies on actually refers to an AAC in its true form—"a rate that adjusts only subject to after-the-fact review, and not prior review, is a rate that can and should be legitimately considered an automatic adjustment clause."[46] This language mirrors the Commission's statutory definition of an AAC, "a provision of a rate schedule that provides for rate increases or decreases or both, without prior hearing."[47] Importantly, nowhere in the

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[43] *Supra*, note 17.
[44] *Id.*
[45] *Id.* emphasis added.
[46] *Id.*
[47] ORS 757.210(b).

Commission's statutory framework does it mention that an AAC inherently allows for any sort of true-up. That is to say, there is no retroactive component. CUB will elaborate on this interplay in legal briefing.

Q. Is there anything else you would like to add on this topic?

A. PGE has failed to address CUB's testimony that the Commission has long utilized deferred accounting for a wide variety of regulatory applications beyond those just for tracking truly unforeseen costs.[48] PGE has also failed to respond to CUB's testimony that AACs and deferrals are already distinct mechanisms.[49] Including a deferred accounting mechanism alongside an AAC plays an important role in Oregon utility regulation to ensure that utilities operate efficiently and to ensure a utility's rates remain just and reasonable.[50] PGE has failed to meet its burden of proof to provide any compelling rationale to alter the Commission's longstanding process regarding the interplay of deferrals and AACs, which are two distinct mechanisms. CUB will respond to the remainder of PGE's arguments regarding the rule against retroactive ratemaking and the interplay of the two statutes in legal briefing.

VI. DECOUPLING

Q. What incentive does traditional cost-of-service regulation offer?

A. Under traditional cost-of-service regulation, Actual Revenues = Price * Units of Consumption. This relationship means that utilities make more money when they

[48] UE 416 – CUB/200/Jenks/48-49.
[49] *Id*. at 49.
[50] *Id*. at 50-51.

sell more units of energy. The inverse is also true: utilities make less when sell fewer units of energy.

Q. What is decoupling?

A. Decoupling is a tool that breaks the link between how much a utility delivers energy and the revenues it collects. Decoupling is a system that uses a true-up mechanism, which ensures that the utility recovers its fixed costs. The purpose is to “decouple profits” from sales volumes so utilities will not have a disincentive to fix cost recovery to pursue conservation.

Q. What is PGE’s history on decoupling?

A. In Oregon, decoupling has existed off-and-on for PGE since the 1990s. Most recently, in UE 197, PGE adopted a sales normalization adjustment (SNA) for residential and small commercial customers. When implementing PGE’s decoupling mechanism, the Commission found that it shifted the risk of fixed cost recovery to customers and originally required the utility to offset that risk by taking a 10-basis point deduction from ROE. For gas utilities, the trade off to customers for taking on this additional risk was a requirement that energy efficiency programs through the Energy Trust of Oregon (ETO) be offered to customers.

Q. What did PGE state on decoupling?

A. In Opening testimony, PGE did not propose a new decoupling mechanism. Instead, PGE described a sales normalization adjustment, with a soft 3% cap. PGE also indicated that it supports decoupling if the Commission also approves its changes to shift the risk of power cost recovery in the PCAM to customers.

Q. What did NWEC/NRDC state on decoupling?

A. NWEC and NRDC are supporting reinstituting the SNA for Schedule 7 and 32 with a 3% soft cap. NWEC/NRDC argue that decoupling is needed to promote cost effective energy efficiency. NWEC/NRDC also argue that utilities need to move away from a business model linked to commodity sales.

Q. What did Staff state on decoupling?

A. Staff does not support restoring the decoupling mechanism. Staff argues that the ETO serves as an unbiased manager of energy efficiency investments in energy efficiency. Staff does not support PGE linking the PCAM to decoupling.

Q. What did PGE tell investors when ending decoupling in 2022?

A. On July 28, 2022, Portland General Electric conducted its quarter 2 earnings call for 2022. In that earnings call's question and answer period, an analyst asked PGE management to quantify the impact of getting rid of decoupling into PGE's long-term trajectory. PGE's management responded that they bargained to remove decoupling in 2022 because they expect significant load growth in the future, and that it would be beneficial for the Company to discontinue decoupling.

Q. What is CUB's position on decoupling?

A. Because Oregon has the ETO as the entity that enacts energy efficiency programs and because Oregon has a legal requirement that all cost-effective energy efficiency programs be acquired under SB 1547, CUB believes the benefits of decoupling have been reduced in Oregon. Because utilities do not manage any energy efficiency programs, utilities' ability to act on any disincentive to fund energy efficiency is limited.

At the same time, CUB believes that the shift in risk onto customers from decoupling is not very large and may be outweighed by the benefits of decoupling. In the 2022 Q2 earnings call, PGE indicated that customer growth may make removing decoupling beneficial to the Company, which makes CUB wary of keeping decoupling removed. Decoupling will ensure that some of the benefits of load growth due to electrification between general rates case will flow through to customers. In CUB's experience with other utilities, decoupling has minimized regulatory conflicts over the load forecast in general rate cases, because decoupled utilities net income is not affected by changes in sales volumes versus estimated sales volumes. Overall, CUB is not opposed to the Commission reinstituting decoupling with a sales normalization adjustment with a soft cap of 3%.

CUB does oppose PGE's attempt to use decoupling as leverage to get its PCAM proposal approved. The Commission has already determined that decoupling shifts the risk of fixed cost recovery from shareholders to customers. PGE's argument is that we will agree to shift most of the risk of fixed cost recovery from shareholders to customers, but only if we also get to shift most of the risk of variable cost recovery from shareholders to customers. This is equivalent of someone saying you can give me $5 but only if you also give me $10. CUB rejects this bargain and linkage.

Q. Does this conclude your testimony?

A. Yes.

CUB/401
Jenks/1

PGE

Investor Presentation

PORTLAND GENERAL ELECTRIC

July 28, 2023

CUB/401
Jenks/2

Cautionary statement

Information Current as of July 28, 2023
Except as expressly noted, the information in this presentation is current as of July 28, 2023 – the date on which PGE filed its Quarterly Report on Form 10-Q for the quarter ended June 30, 2023 – and should not be relied upon as being current as of any subsequent date. PGE undertakes no duty to update this presentation, except as may be required by law.

Forward-Looking Statements
Statements in this presentation that relate to future plans, objectives, expectations, performance, events and the like may constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements represent our estimates and assumptions as of the date of this report. The Company assumes no obligation to update or revise any forward-looking statement as a result of new information, future events or other factors.

Forward-looking statements include statements regarding the Company's full-year earnings guidance (including expectations regarding annual retail deliveries, hydro conditions, wind generation, normal thermal plant operations, operating and maintenance expense and depreciation and amortization expense) as well as other statements containing words such as "anticipates," "based on," "believes," "conditioned upon," "considers," "could," "estimates," "expects," expected," "forecast," "goals," "intends," "needs," "plans," "predicts," "projects," "promises," "seeks," "should," "subject to," "targets," "will likely result", "will continue," or similar expressions.

Investors are cautioned that any such forward-looking statements are subject to risks and uncertainties, including, without limitation: the timing or outcome of various legal and regulatory actions; changing customer expectations and choices that may reduce demand for electricity; the sale of excess energy during periods of low demand or low wholesale market prices; operational risks relating to the Company's generation and battery storage facilities, including hydro conditions, wind conditions, disruption of transmission and distribution, disruption of fuel supply, and unscheduled plant outages, which may result in unanticipated operating, maintenance and repair costs, as well as replacement power costs; delays in the supply chain and increased supply costs (including application of tariffs impacting solar module imports), failure to complete capital projects on schedule or within budget, inability to complete negotiations on contracts for capital projects, failure of counterparties to perform under agreement, or the abandonment of capital projects, which could result in the Company's inability to recover project costs, or impact our competitive position, market share, revenues and project margins in material ways; default or nonperformance of counterparties from whom PGE purchases capacity or energy, which require the purchase of replacement power and renewable attributes at increased costs; complications arising from PGE's jointly-owned plant, including ownership changes, regulatory outcomes or operational failures; the costs of compliance with environmental laws and regulations, including those that govern emissions from thermal power plants; changes in weather, hydroelectric and energy market conditions, which could affect the availability and cost of purchased power and fuel; the development of alternative technologies; changes in capital and credit market conditions, including volatility of equity markets, reductions in demand for investment-grade commercial paper or interest rates, which could affect the access to and availability or cost of capital and result in delay or cancellation of capital projects or execution of the Company's strategic plan as currently envisioned; general economic and financial market conditions, including inflation; the effects of climate change, whether global or local in nature; unseasonable or severe weather conditions, wildfires, and other natural phenomena and natural disasters that could result in operational disruptions, unanticipated restoration costs, third party liability or that may affect energy costs or consumption; the effectiveness of PGE's risk management policies and procedures; PGE's ability to effectively implement Public Safety Power Shutoffs (PSPS) and de-energize its system in the event of heightened wildfire risk; cyber security attacks, data security breaches, physical attacks and security breaches, or other malicious acts, which could disrupt operations, require significant expenditures, or result in claims against the Company; employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and the ability to recruit and retain key employees and other talent and turnover due to macroeconomic trends; PGE business activities are concentrated in one region and future performance may be affected by events and factors unique to Oregon; widespread health emergencies or outbreaks of infectious diseases such as COVID-19, which may affect our financial position, results of operations and cash flows; failure to achieve the Company's greenhouse gas emission goals or being perceived to have either failed to act responsibly with respect to the environment or effectively responded to legislative requirements concerning greenhouse gas emission reductions; political and economic conditions; and risks and uncertainties related to All-Source RFP final shortlist projects, including regulatory processes, transmission capabilities, system interconnections, permitting and construction delays, legislative uncertainty, inflationary impacts, supply costs and supply chain constraints. As a result, actual results may differ materially from those projected in the forward-looking statements. Risks and uncertainties to which the Company are subject are further discussed in the reports that the Company has filed with the United States Securities and Exchange Commission (SEC). These reports are available through the EDGAR system free-of-charge on the SEC's website, www.sec.gov and on the Company's website, investors.portlandgeneral.com. Investors should not rely unduly on any forward-looking statements.

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The Company

PGE at a glance

Quick facts

- Vertically integrated electric utility encompassing generation, transmission and distribution
- Approximately 926,000 retail customers within a service area of approximately 1.9 million residents[(1)]
- Roughly half of Oregon's population lives within PGE service area, encompassing 51 incorporated cities entirely within the State of Oregon
- Roughly two-thirds of Oregon's commercial and industrial activity occurs in PGE service area

Leading the way to a clean energy future for Oregon

- Our goals align with the 100% clean energy by 2040 framework. The targets to reduce baseline greenhouse gas emissions from power served to Oregon retail customers are:
  - 80% reduction in greenhouse gas emissions by 2030
  - 90% reduction in greenhouse gas emissions by 2035
  - 100% reduction in greenhouse gas emissions by 2040

3,300+ MWs of Generation

Financial snapshot

- 2022 revenue: $2.6 billion
- 2022 diluted earnings per share: $2.60 GAAP, $2.74 adjusted non-GAAP[(2)]
- Net utility plant assets: $8.0 billion[(1)]

(1) As of December 31, 2022

(2) In 2022, GAAP net income was $233 million, or $2.60 per diluted share. After adjusting for the impacts of released deferrals related to 2020, non-GAAP net income was $247 million, or $2.74 per diluted share. The net effect of the deferral release was $0.14 per diluted share (see appendix for important information about non-GAAP measures, guidance, and reconciliations)

Investment thesis

Investing in a reliable and clean energy future

- Adopting 100% clean energy by 2040 framework
- Secured 311 MW of renewable generation and 475 MW of non-emitting capacity in 2021 RFP. 2,700 to 3,700 MW of additional non-emitting resources remain to be procured through multi-stage RFP processes through 2030

Building a smarter more resilient grid

- Investing in our system to maintain and increase resiliency to mitigate against extreme weather and wildfires
- Modernizing our grid with a community-centered distribution system to advance environmental justice, accelerate distributed energy resources and maximize grid benefits

Focusing on operational effectiveness and efficiency

- 5% to 7% long-term EPS growth(1) and dividend growth guidance(2)
- Continuing to implement efficiencies and manage costs through technology

High-growth service area

- Urban service territory with strong growth in residential and high-tech industrial segments
- Growing number of customer connects and 2% long-term load growth, through 2027

Constructive regulatory environment

- Regulatory mechanisms to recover costs and add renewables, including a Renewable Adjustment Clause, Wildfire Mitigation Automatic Adjustment Clause and forward test year
- Vertically integrated, regulated utility

Delivering exceptional customer experiences

- No. 1 ranked renewable power program in the Unites States for 13 years(3)
- Named a 2022 Environmental Champion Utility for PGE's environmental stewardship efforts on behalf of customers(4)

(1) Long-term EPS growth base year is 2022 adjusted results

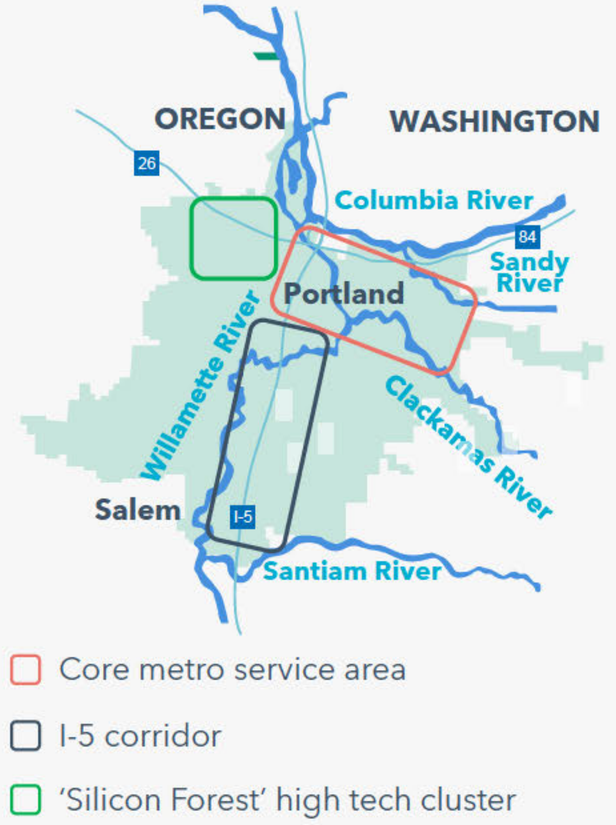
(2) The amount and timing of dividends payable and the dividend policy are at the sole discretion of the Portland General Electric Board of Directors and, if declared and paid, dividends may be in amounts that are materially less than projected. EPS estimates and projections are based on assumptions and there can be no assurance regarding the amount of future earnings consistent with earnings guidance

(3) National Renewables Energy Laboratory. NREL did not release rankings in 2011

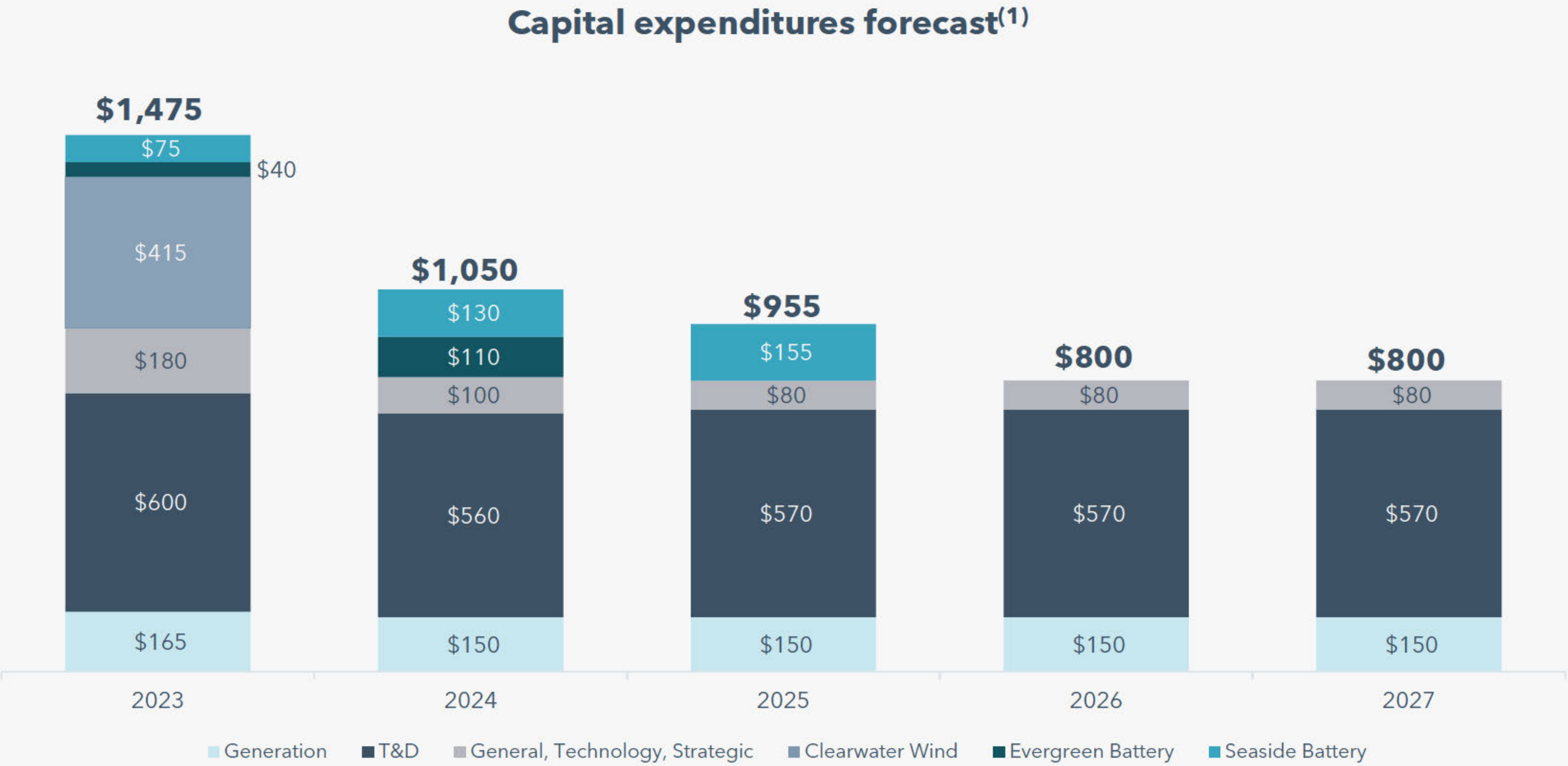
(4) Escalent Cogent Syndicated Utility Trusted Brand & Customer Engagement: Residential management advisory study

Diverse, growing service area

- Growing **core urban service area** with strong population growth supporting services (government, education, restaurants, healthcare, and other services)
- **I-5 corridor** and port access provide opportunity for transportation and warehousing and market access for traditional manufacturing (wood products, food, metals)
- **'Silicon Forest' high tech cluster** includes R&D and component manufacturing. Hillsboro fiber infrastructure provides unique opportunity for continued data center development
- Residential customers accounted for 38% of retail deliveries in 2022, commercial 34%, industrial 28%
- Strong industrial load growth in recent years, 6.8% CAGR from 2017-2022
- Forecast long-term annual energy deliveries growth of 2% driven by growth in high-tech industrial customers and stability in residential and commercial class, as increases in customer count are offset by more efficient usage



Reliability and resiliency investments

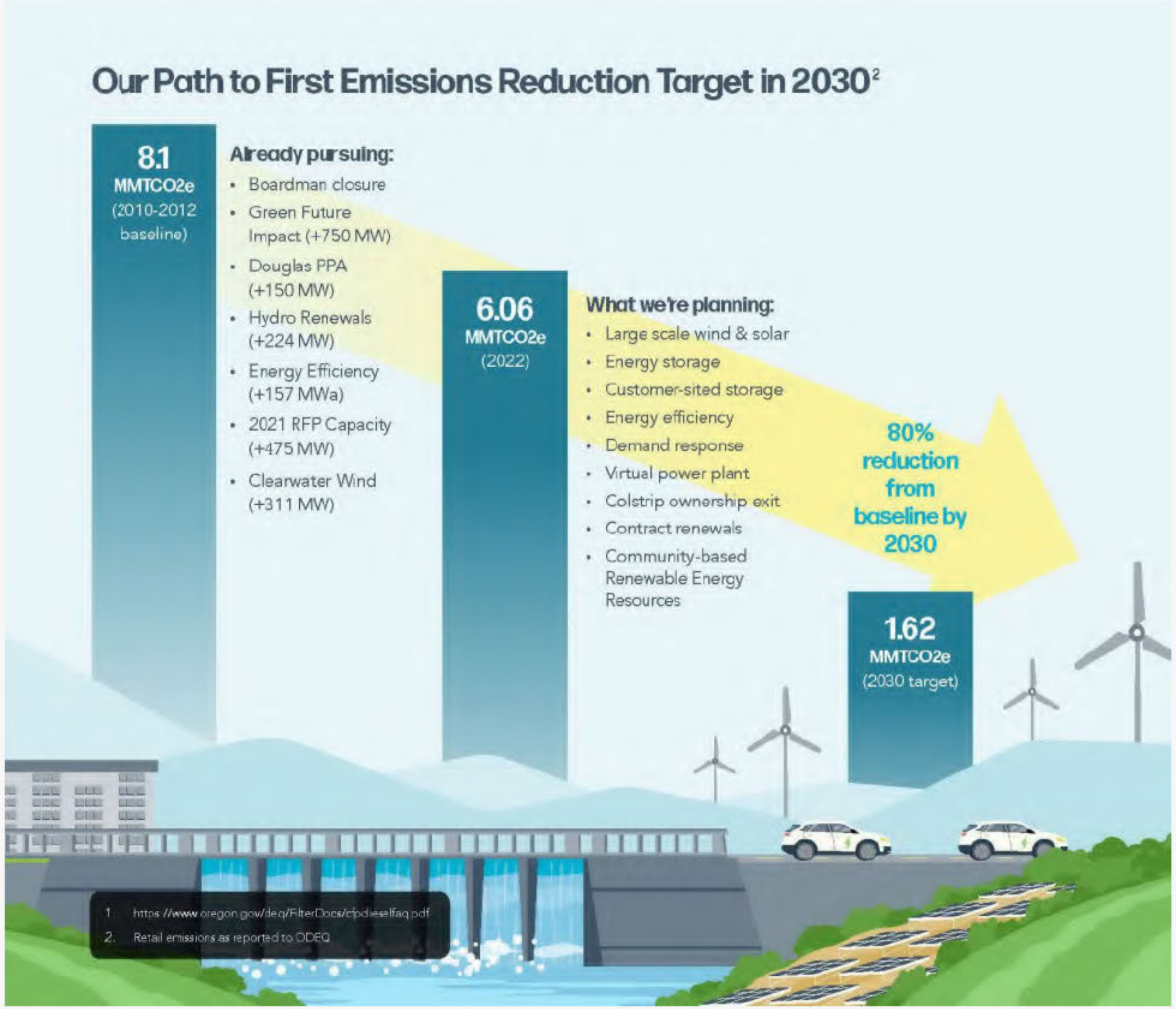


Note: Dollar values in millions. Capital expenditures exclude allowance for funds used during construction. These are projections based on assumptions of future investment. Actual amounts expended will depend on various factors and may differ materially from the amounts reflected in this capital expenditure forecast

(1) Values presented do not include incremental potential investments for future RFP cycles

Clean energy transition

Advancing toward a clean energy future



PGE has taken significant steps to decarbonize its system:

- 2022 emissions 25% below HB 2021 baseline levels (average emissions 2010-2012)

Meaningful steps underway to meet 2030 emissions targets:

- Removing coal from our portfolio to meet our legislative requirement
- Secured 311 MW of renewable generation (Clearwater Wind) and 475 MW of non-emitting dispatchable capacity (Seaside, Evergreen and Troutdale batteries) in the 2021 RFP
- 2,700 to 3,700 MW of additional non-emitting resources remain to be procured through multi-stage RFP processes through 2030

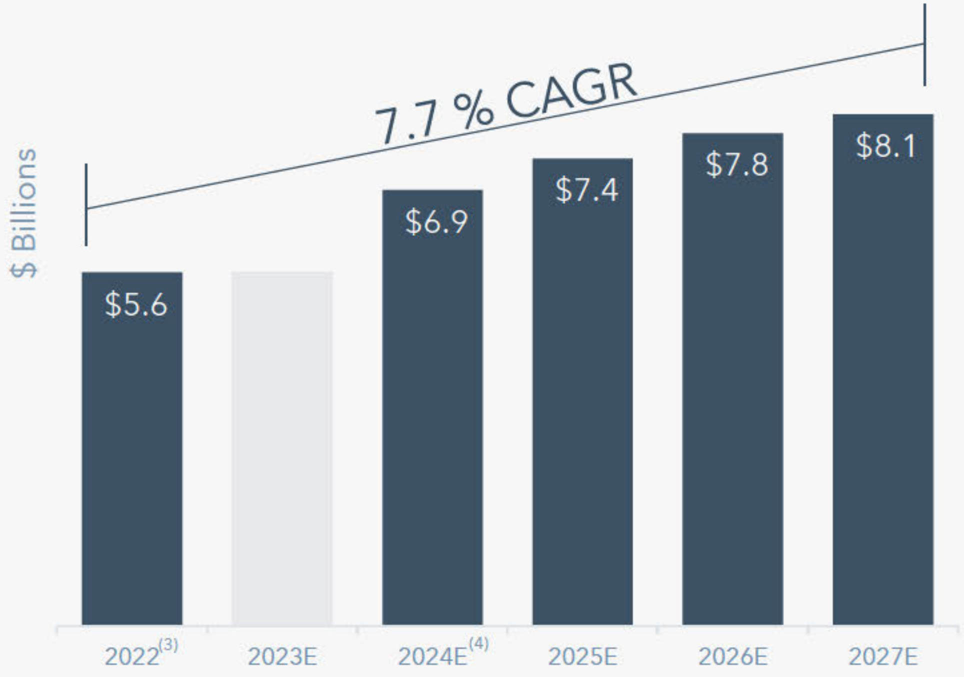
Our decarbonization strategy is multi-faceted to support reliable and affordable power:

- Clean energy
- Customer-sited solutions
- Technology and innovation
- Regional solutions to resource adequacy

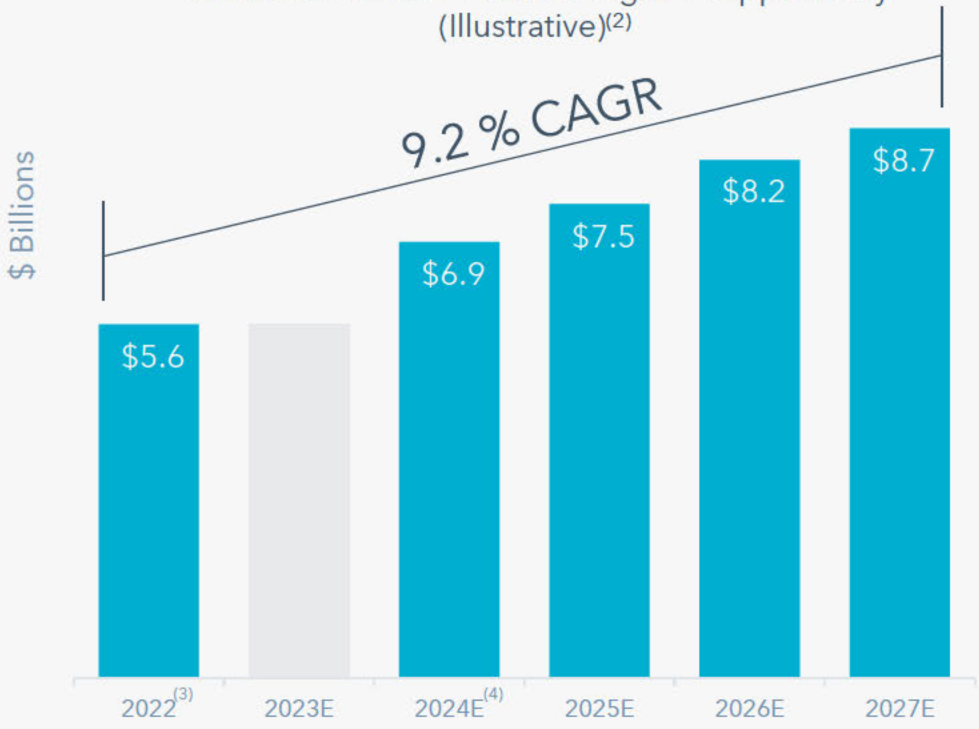
Illustrative rate base growth

- PGE's five-year base plus Clearwater Wind, Seaside and Evergreen battery capital expenditure forecast of $5.1 billion drives 7.7% average rate base growth from 2022 base year
- Illustrative incremental RFP opportunities[2] potentially increase average rate base growth to 9.2%, from 2022 base year
- Amounts presented below are for illustrative purposes and represent potential values based on the assumptions outlined below. Amounts do not represent guidance and actual amounts may differ materially

Average Rate Base: Base Capital + 2021 RFP PGE-Owned Resources (Illustrative)[1]



Average Rate Base: Base Capital + 2021 RFP PGE-Owned Resources + Remaining RFP Opportunity (Illustrative)[2]



(1) Base + 2021 RFP PGE-Owned Resources scenario illustrates the potential impact of the following assumptions: a) 2024 beginning earnings power rate base is assumed consistent with the 2024 GRC value ($6.3B) plus capex of $415M for the Clearwater wind project; b) annual capital expenditures from 2024-2027 consistent with current capital expenditures forecast on slide 7; and c) 2023 depreciation and amortization of $455M (mid-point of 2023 earnings guidance assumption) and 25-year useful life for new asset additions thereafter

(2) The incremental opportunity from RFPs illustrates the potential impact of the following assumptions: a) a total remaining IRP opportunity of 3,200 MW (mid-point of remaining resource need of 2,700 to 3,700 MW, including both energy and capacity resources); b) 25% ownership of the midpoint 3,200 MW opportunity; c) $1,900 installed cost per KW (based on indicative values for 2021 RFP PGE-Owned Resources); d) RFP projects procured in serial cycles and with evenly spread project spend through year-end 2029 (Note: This is illustrative and actual RFP opportunity spend may be unevenly distributed); and e) 25-year useful life for RFP asset additions

(3) 2022 rate base value based on UE 394 2022 GRC Rate Base amount, inclusive of Colstrip

(4) 2024 beginning rate base value based on UE 416 2024 GRC Rate Base initial filing value ($6.3B) plus capex of $415M for the Clearwater wind project

Resource planning and procurement

2023 IRP/CEP Action Plan

Customer Actions

- Increased energy efficiency, distributed energy resources and incorporation of customer demand response

Community-Based Renewable Energy (CBRE) Action

- RFPs for qualifying CBRE resources, 66 MW in service by 2026, 155 MW in service by 2030

Energy Action

- Renewable RFPs, target acquiring 261 MWa per year

Capacity Action

- Capacity RFPs to acquire sufficient capacity to meet forecasted needs

Transmission Actions

- Pursue options to alleviate congestion and upgrade key transmission resources

2023 RFP Timeline

✓ **May 2023** Draft RFP submitted to OPUC for approval

❑ **Q3 2023** Final RFP issuance

❑ **Q4 2023** Bid submissions due

❑ **Q4 2023*** Submit request for acknowledgement of final shortlist to OPUC and shortlist publication

❑ **Q2 2024*** Execution of final contracts with winning bidders

*Subject to change depending on the quantity and complexity of bids received and should circumstances require

2024 General Rate Case

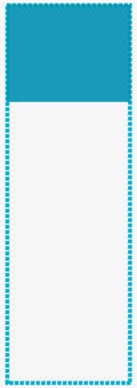
Rate Case Key Terms	
Rate Base	$6.3 billion
Rate Base Increase	$859 million, 16%
ROE	9.8%
Capital Structure	50/50
Cost of Debt	4.32%
Cost of Capital	7.06%
Revenue Requirement Increase	$338 million

Key Proposals	• Modify Power Cost Adjustment Mechanism (PCAM) structure
	  • Remove deadbands with 90/10 sharing of cost variances
	  • Provide for cost recovery during reliability contingency events
	  • +/- 2.5% rolling cap on customer price changes year-over-year for cost variances, amounts beyond cap roll to the next year
	  • Update forecast modeling to reflect new market and climate dynamics
	• Clarify associated battery storage will be included in Renewable Adjustment Clause filings

Management cannot predict the outcome of the rate case and all items are subject to OPUC approval

Key Strengths

Focus on customers



Top quartile system reliability(1)

Edison Electric Institute
2021

#1

No.1 renewable energy program in the nation for 13 years(2)

National Renewables
Energy Laboratory
2021

Environmental Champion

Utility Trusted Brand &
Customer Engagement™
Residential Study Escalent
2022

#3

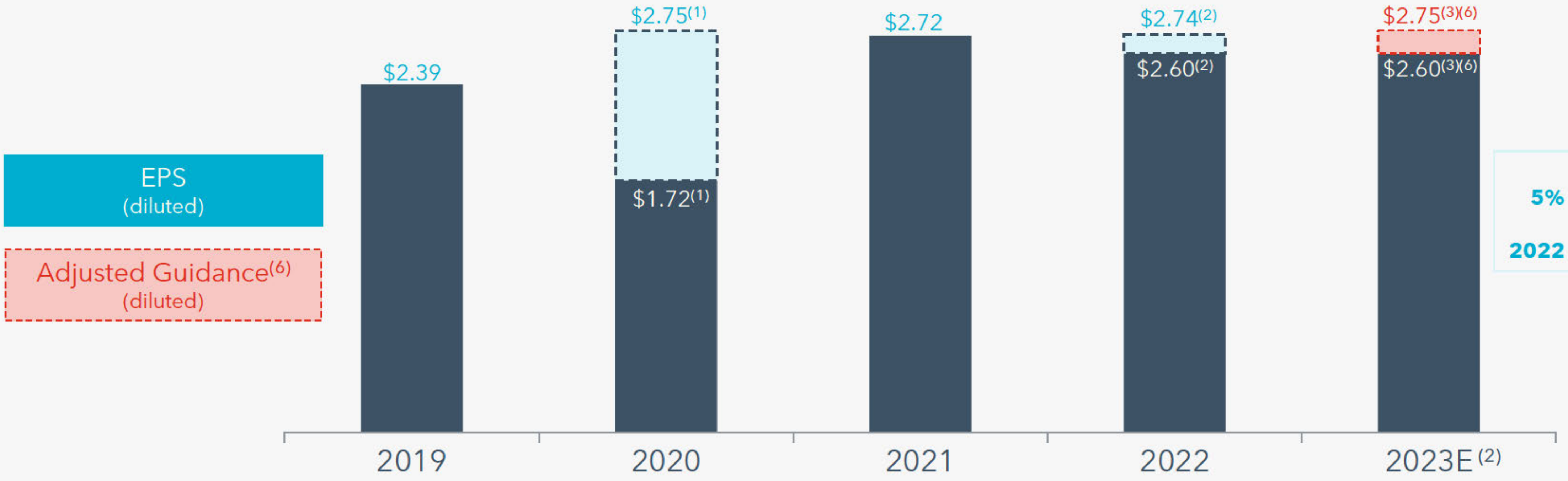
No. 3 utility in the U.S. for customer experience

Forrester
The US
Customer Experience
Index
2022

(1) Overall System – SAIFI (Excluding Major Events)
(2) NREL did not release rankings in 2011

CUB/401
Jenks/14

Long-term financial performance

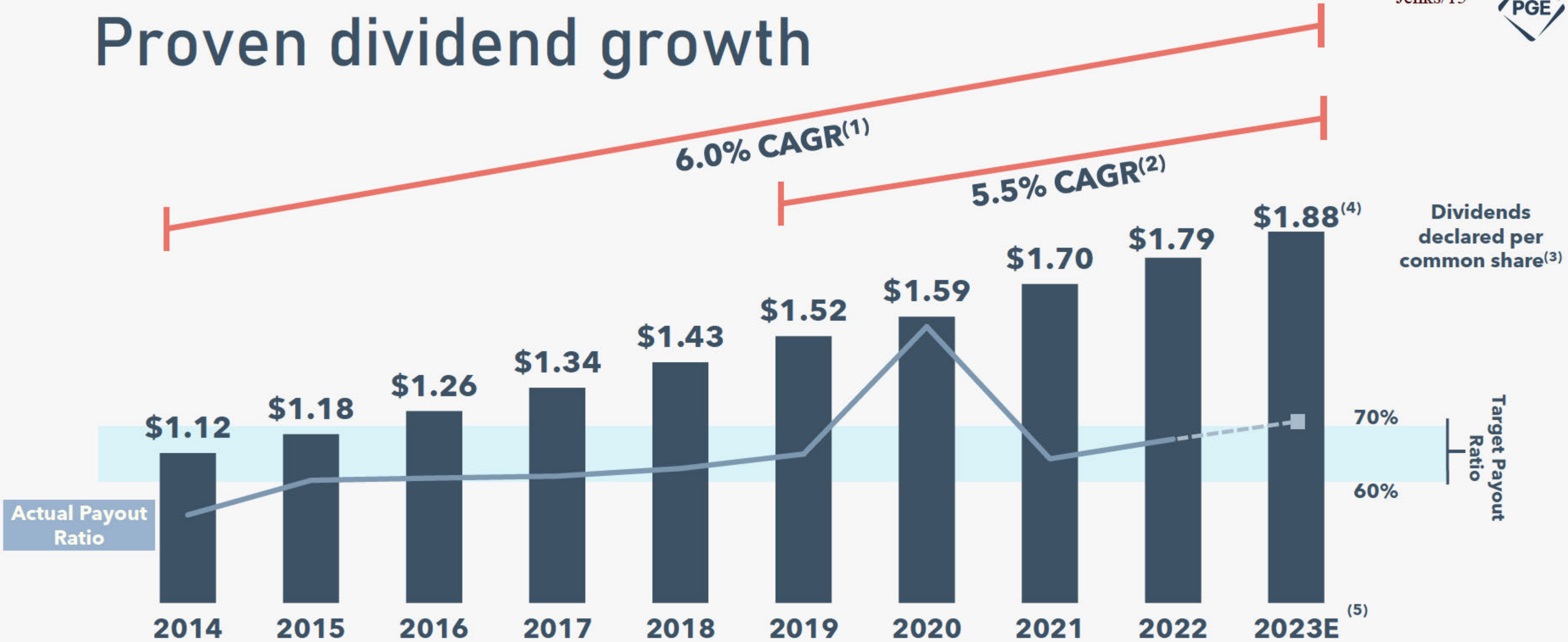


Long-term 5% to 7%[3] earnings growth from 2022 adjusted base year

	2019	2020	2021	2022	2023E [2]
Accounting ROE[5]	8.4%	6.0%	9.2%	8.5%	8.3% - 8.8%[3][4][6]
Allowed ROE	9.5%	9.5%	9.5%	9.5%	9.5%

(1) In 2020 GAAP net income was $155 million, or $1.72 per diluted share. After adjusting for the impacts of the Energy Trading Losses, non-GAAP net income was $247 million, or $2.75 per diluted share. The net effect of the energy trading losses was $1.03 per diluted share (see appendix for important information about non-GAAP measures, guidance, and reconciliations)
(2) In 2022, GAAP net income was $233 million, or $2.60 per diluted share. After adjusting for the impacts of released deferrals related to 2020, non-GAAP net income was $247 million, or $2.74 per diluted share. The net effect of the deferral release was $0.14 per diluted share (see appendix for important information about non-GAAP measures, guidance, and reconciliations)
(3) Estimates and projections are based on assumptions and there can be no assurance regarding the amount of future earnings consistent with earnings guidance and earnings growth guidance
(4) 2023E Accounting ROE calculated based on adjusted earnings guidance range of $2.60 to $2.75 (see appendix for important information about non-GAAP measures, guidance, and reconciliations)
(5) Return on average equity
(6) See appendix for important information about non-GAAP measures, guidance, and reconciliations

Proven dividend growth

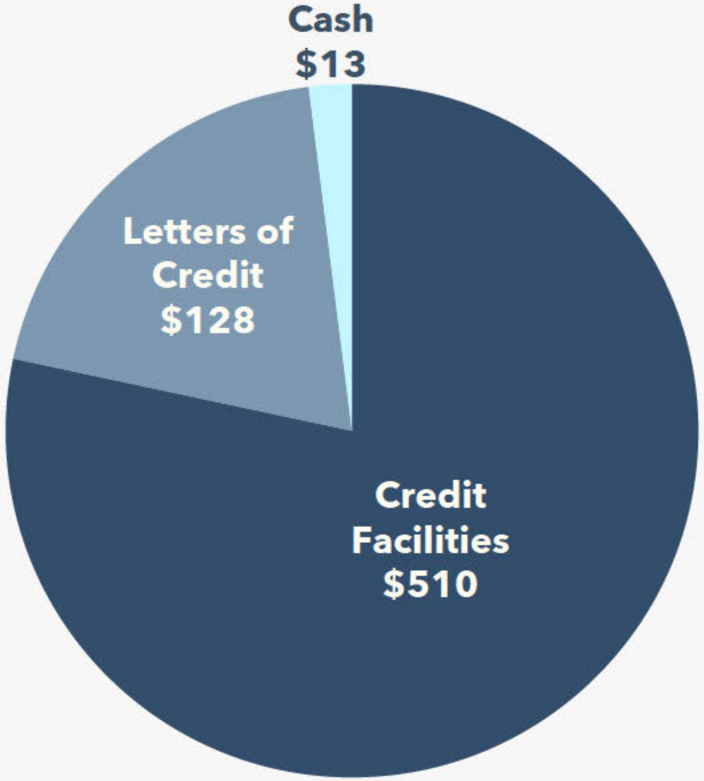


Long-term dividend growth guidance of 5-7%(4)

(1) Compound Annual Growth Rate from 2014 through 2023E
(2) Compound Annual Growth Rate from 2019 through 2023E
(3) Represents annual dividends declared per common share
(4) Estimates and projections are based on assumptions and there can be no assurance regarding the amount of future dividends. The amount and timing of dividends payable and the dividend policy are the sole discretion of the Portland General Electric Board of Directions, and if declared and paid, dividend may be in amounts that are less than projected
(5) 2023E estimated dividend payout ratio calculated using the midpoint of adjusted earnings guidance of $2.60 to $2.75

Liquidity and financing

Total Liquidity: $651 million
as of June 30, 2023 (dollars in millions)



Ratings	S&P	Moody's
Senior Secured	A	A1
Senior Unsecured	BBB+	A3
Commercial Paper	A-2	P-2
Outlook	Stable	Stable

Actual and expected 2023 debt financings (dollars in millions)	Q1	Q2	Q3	Q4
Long-term debt	$100(1)	-	$300	$200
Short-term debt		$140		

Equity financings (dollars in millions)	Total facility	Settled to-date(2)
2022 Equity Forward Sale Agreement(2)	$484	$484
At-The-Market Offering Program(3)	$300	-

(1) Bond purchase agreement was entered on November 30, 2022, and Bonds were issued and funded in full on January 13, 2023
(2) In 2022, PGE entered into an equity forward sale agreement (EFSA) in connection with a public offering of 11,615,000 shares (including 1,515,000 shares in connection with the underwriters' exercise of their option to purchase additional shares) of its common stock. In March 2023, the Company issued 7,178,016 shares pursuant to the EFSA and received net proceeds of $300 million. In June 2023, the Company issued 2,212,610 shares pursuant to the EFSA and received net proceeds of $92 million. In July, the Company issued 2,224,374 shares pursuant to the EFSA and received net proceeds of $92 million. Amounts presented are net of underwriting discount of $1.23625 per share
(3) PGE entered into an at-the-market offering program in the second quarter of 2023. The proceeds from the issuances of common stock will be used for general corporate purposes and renewable energy investments

Environmental, Social and Governance

ESG highlights

Decarbonize | Electrify | Perform

GHG Emissions Reduction	In 2022, PGE served 39% of customer load from specified non-emitting energy sources. 2022 emissions were 25% below HB 2021 baseline levels (average emissions 2010-2012)
Clean Energy Investment	Brought the first-of-its scale combined wind, solar, and storage facility at Wheatridge fully online and announced plans for the new Clearwater 311 MW wind energy facility to serve customers by close of 2023 and 475 MW of battery energy storage systems to begin serving customers in 2024 and 2025
Green Financing Framework	Entered a new phase of our sustainable finance strategy in 2022 by closing on sustainability-linked revolving credit facility, executing a $499 million equity forward sale agreement and issuing $460 million in debt, of which $100 million was funded in 2023 to finance eligible green investments under our new Green Financing Framework
Diversity, Equity and Inclusion	Amidst tight labor market conditions, PGE continued to attract and retain a diverse workforce, with women accounting for a third and Black, Indigenous and People of Color (BIPOC) employees more than a fourth, of the leadership at PGE

Our 2022 ESG Report highlights key initiatives and achievements that support PGE's **commitment to decarbonization and advancing well-being for customers, employees, communities and the environment**

Diverse and experienced Board

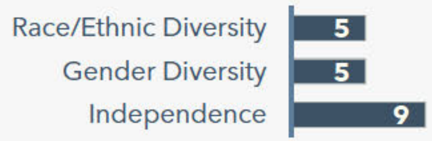
	Name	Age	Director Since	Industry/Experience	Diversity	Committee Membership[1]	Other Public Boards
	**Dawn Farrell** Independent	63	2022	Utilities	White/Female	• Finance • Governance	1
	**Mark Ganz** Independent	62	2006	Healthcare/Law	White/Male	• Audit & Risk • Compensation	0
	**Marie Oh Huber** Independent	61	2019	Law/Technology	Asian/Female	• Compensation • Governance	1
	**Kathryn Jackson** Independent	65	2014	Technology/Environmental	White/Female	• Audit & Risk, Chair • Governance	2
	**Michael Lewis** Independent	60	2021	Utilities	African American/Male	• Compensation • Finance, Chair	1
	**Michael Millegan** Independent	64	2019	Technology	African American/Male	• Audit & Risk • Finance	2
	**Lee Pelton** Independent	72	2006	Education/Non-Profit Foundations	African American/Male	• Audit & Risk • Governance, Chair	0
	**Patricia Pineda** Independent	70	2022	Industry/Law/Human Resources	Hispanic/Female	• Compensation, Chair • Finance	3
	**Maria Pope** President and CEO	57	2018	Utilities/Finance	White/Female		1
	**Jim Torgerson** Independent Chair	69	2021	Energy/Finance	White/Male	• Audit & Risk • Finance	1

Track record of thoughtful refreshment enables us to have a Board with the experience and diverse perspectives needed to oversee our business

Diverse and Independent Leadership

Board Tenure

Board Diversity



Board Skills

(1) Key to Abbreviated Committee Names: Compensation- Compensation, Culture and Talent Committee, Governance- Nominating, Governance and Sustainability Committee

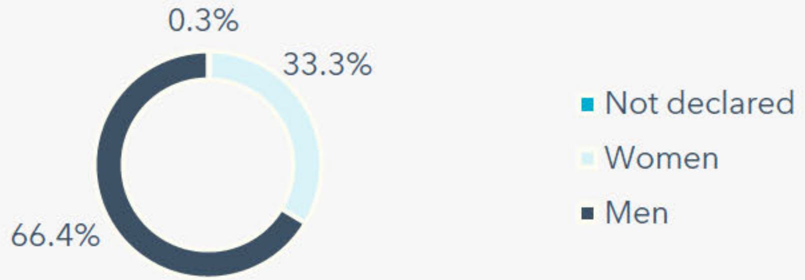
Note: Information current as of March 7, 2023

Diversity, equity, and inclusion

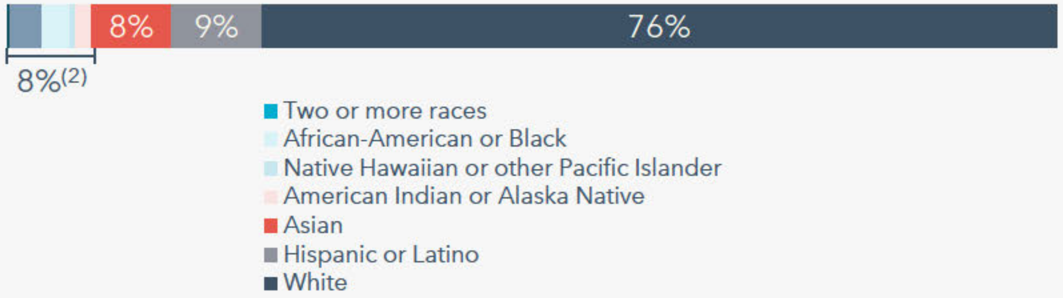
Committed to DEI across our business

- **Partners and suppliers:** Increased our supplier diversity to 14% of total supplier spending in 2022, up from 10% in 2021
- **Awareness, education, and training:** Racial equity education for our board, leadership and employees
- **Recruitment and development:** Development opportunities for underrepresented, high-potential employees interested in leadership
- **Awards and recognition:** Perfect score on the Human Rights Corporate Equality Index and Gender-Equality Index, with active participation in the CEO Action for Diversity & Inclusion
- **Competitive pay and benefits:** Diversity metrics included in incentive programs. PGE employees in the same role, with comparable work experience, at the same location earn a near-perfect dollar-for-dollar pay
- **Policies and purpose:** Human Rights Policy Statement established, promoting our commitment to our employees, communities, suppliers and partners

Workforce by Gender(1)



Workforce Racial/Ethnic Diversity(1)



(1) As of December 31, 2022

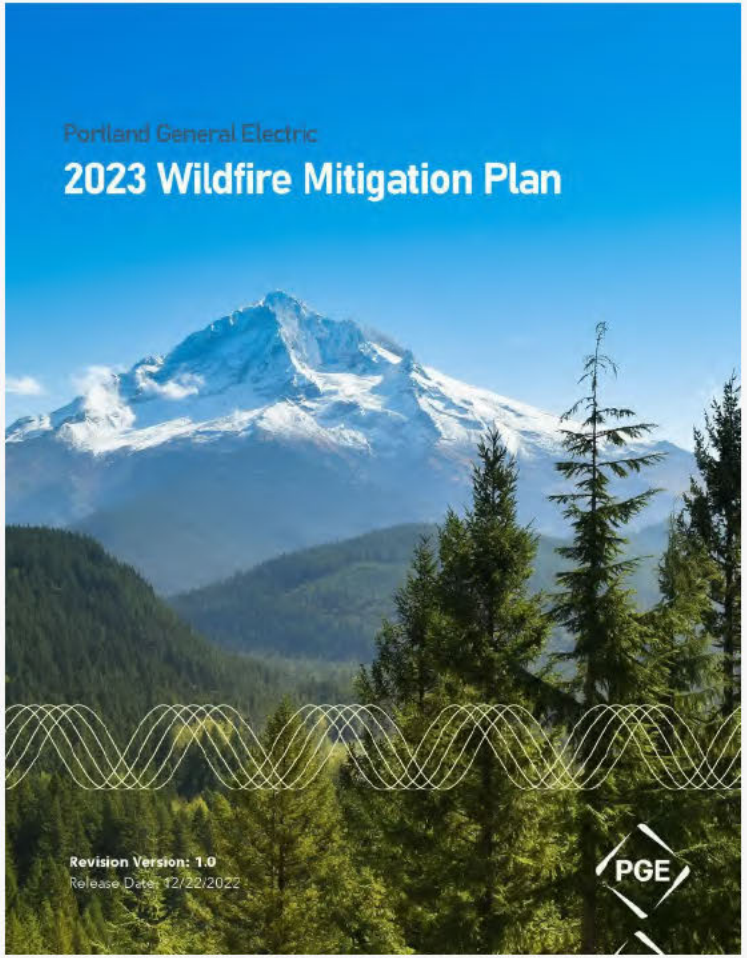
(2) Two or more races, 3%; African-American or Black, 3%; Native Hawaiian or other Pacific Islander, 1%; American Indian or Alaska Native, 1%;

Appendices

Wildfire mitigation and risk management

PGE prioritizes protecting the lives and property of customers, coworkers and the communities we serve

- Approved **Wildfire Mitigation Plan (Docket UM 2208)**
- Robust **tree trimming** and **vegetation management** program
- Ongoing **focus on system hardening**:
  - Fire resistant, ductile iron transmission and distribution poles in priority wildfire areas
  - Clearance of critical transmission lines
  - Expanding use of underground cables
- **Advanced technologies** for monitoring and early alerts
  - Wildfire cameras
  - Intelligent reclosers
  - Weather stations
- **Inverse condemnation is not applied to utilities for wildfires under current Oregon law**



Constructive regulatory / policy environment

Oregon

- Oregon legislation requires 100% clean energy by 2040
- Oregon Public Utility Commission
  - Governor-appointed 3-member commission with staggered 4-year terms
  - Commission has consistently approved investments in renewables, going back to Biglow Canyon Wind Farm, which went online 15 years ago
- Regulatory dynamics support PGE and the transition to clean energy
  - Renewable Portfolio standard (adopted in 2007; increased in 2016)
  - Renewable Adjustment Clause
  - Forward test years
  - Integrated resource planning framework
  - Accelerated depreciation of Colstrip to 2025
  - History of reasonable settlements in rate cases
  - Regulatory support for recovery of storm response and wildfire mitigation costs

Federal

- The Inflation Reduction Act (IRA), which was signed into law in August 2022, is expected to further enhance PGE's already strong prospects for renewables-based growth
- Better positions renewables to be owned and operated by regulated utilities like PGE and makes renewables more affordable for PGE customers
  - Allows for solar projects to elect ITC or PTC
  - Allows for the transfer of tax credits after 2022
  - Standalone storage can earn tax credits
- Makes tax credits available for renewable energy through the later of 2032 or when annual greenhouse gas emission in the U.S. electric sector falls 75% from 2022 levels
  - Effectively increases the competitiveness of renewables relative to conventional generation, bolstering long-term deployment
  - Improves the economics for repowering existing renewables as they age

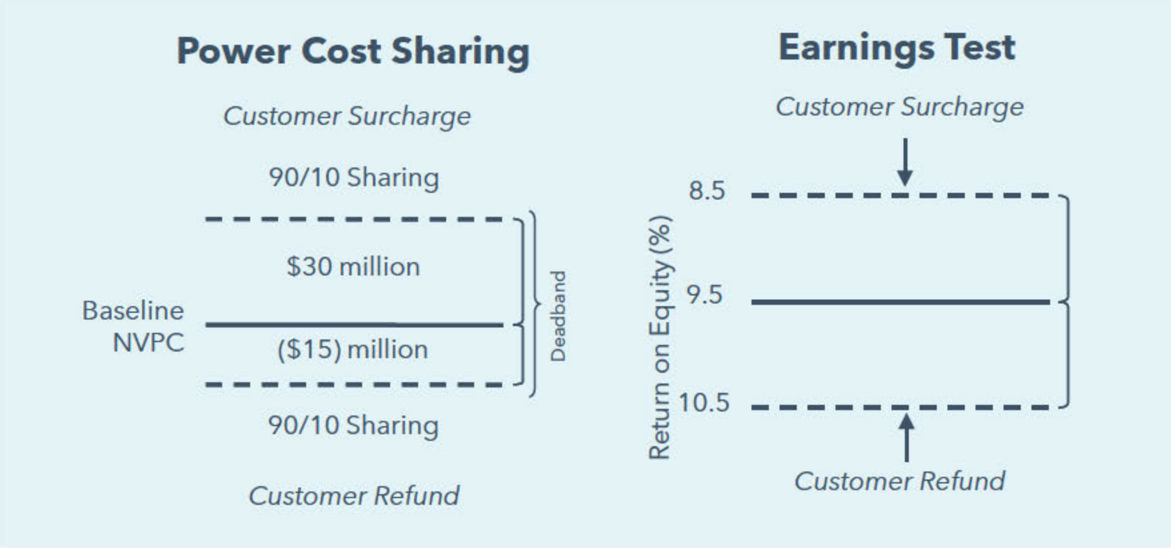
PGE's regulatory environment in Oregon, along with the recently-signed IRA, position the company to play an important role in the decarbonization of Oregon

Recovery of power costs

Annual power cost update tariff

- Annual reset of prices based on forecast of net variable power costs (NVPC) for the coming year
- Subject to OPUC prudency review and approval, new prices go into effect on or around January 1 of the following year

Power Cost Adjustment Mechanism (PCAM)



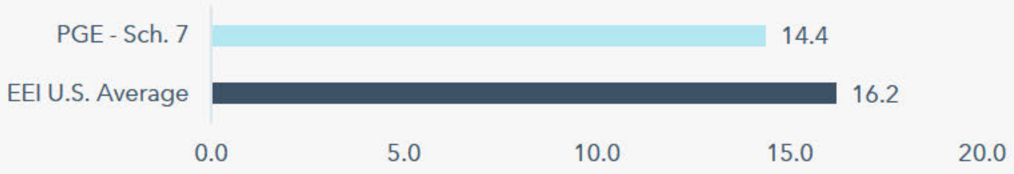
- PGE absorbs 100% of the costs/benefits within the deadband, and amounts outside the deadband are shared 90% with customers and 10% with PGE
- An annual earnings test is applied using the regulated ROE as a threshold
- Customer surcharge occurs if PGE's actual regulated ROE is below 8.5%; ROE will not exceed 8.5% with surcharge
- Customer refund occurs if PGE's actual regulated return is above 10.5%; regulated return will not decrease below 10.5% with refund

Detriment / (Benefit) PCAM Baseline at Year End[1]:										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Over / (Under)	$11	($7)	($3)	($10)	$15	($3)	$5	$ (13)	$30[2]	$23

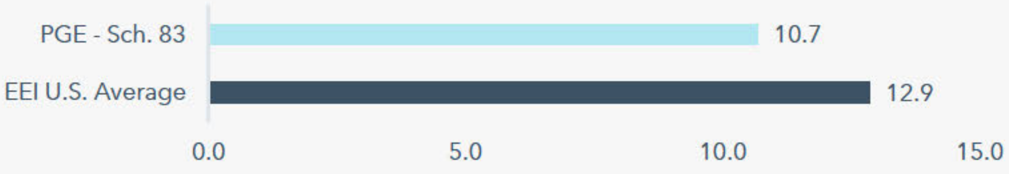
(1) Dollar values in millions
(2) Represents 90% of the excess variance to be collected from customers

Average retail price comparison

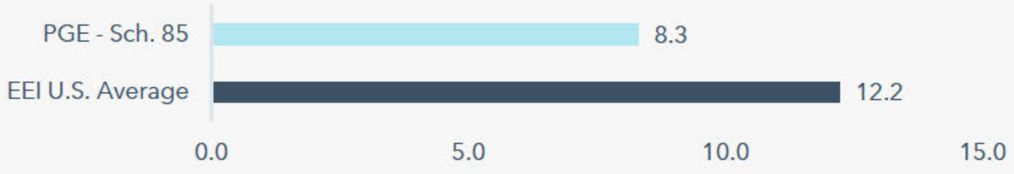
Residential Electric Service Prices:
1,000 kWh monthly consumption
(Prices in cents per kWh)



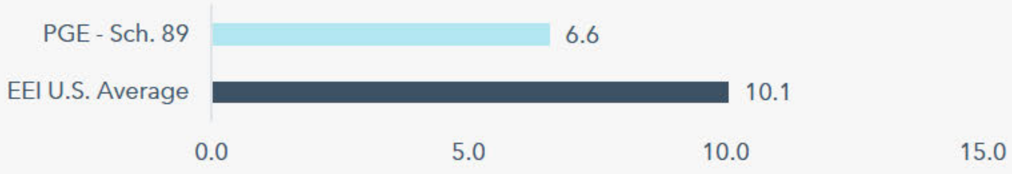
Commercial Electric Service Prices:
40 kW demand and 14,000 kWh monthly consumption
(Prices in cents per kWh)



Industrial Electric Service Prices
1,000 kW peak demand and 400,000 kWh monthly consumption
(Prices in cents per kWh)



Large Industrial Electric Service Prices
50,000 kW peak demand and 32,500,000 kWh monthly consumption
(Prices in cents per kWh)



Note: EEI U.S. Average is based on Investor-owned utilities only
Source: EEI Typical Bills and Average Rates Report for Prices in effect July 1, 2022

2023 Earnings Sensitivities

	Sensitivity	Full-Year Adjusted EPS Impact
Load Growth - Residential[(1)]	± 1%	± \$0.06
Load Growth – Commercial[(1)]	± 1%	± \$0.02
Load Growth – Industrial[(1)]	± 1%	± \$0.01
O&M Expense	± \$10 million	± \$0.07
Interest Rates[(2)]	± 25 bps	± \$0.02
Effective Tax Rate	± 1%	± \$0.03

(1) Assumes incremental load is charged at average retail rate per customer class and served at average Annual Update Tariff (AUT) power cost rate
(2) Assumes interest rate impact for full year on outstanding debt issuances and expected debt financings in 2023

Non-GAAP financial measures

This press release contains certain non-GAAP measures, such as adjusted earnings, adjusted EPS and adjusted earnings guidance. These non-GAAP financial measures exclude significant items that are generally not related to our ongoing business activities, are infrequent in nature, or both. PGE believes that excluding the effects of these items provides a meaningful representation of the Company's comparative earnings per share and enables investors to evaluate the Company's ongoing operating financial performance. Management utilizes non-GAAP measures to assess the Company's current and forecasted performance, and for communications with shareholders, analysts and investors. Non-GAAP financial measures are supplementary information that should be considered in addition to, but not as a substitute for, the information prepared in accordance with GAAP.

Items in the periods presented, which PGE believes impact the comparability of comparative earnings and do not represent ongoing operating financial performance, include the following:

- 2020: Certain energy trading losses
- 2022: Non-cash Wildfire and COVID deferral reversal charge associated with the year ended 2020, resulting from the OPUC's 2022 GRC Final Order earnings test

Due to the forward-looking nature of PGE's non-GAAP adjusted earnings guidance, management is unable to estimate specific items requiring adjustment, which could potentially impact the Company's GAAP earnings (such as potential adjustments described above) for future periods and therefore cannot provide a reconciliation of non-GAAP adjusted earnings per share guidance to the most comparable GAAP financial measure without unreasonable effort.

PGE's reconciliation of non-GAAP earnings for the years ended December 31, 2020, and December 31, 2022 are on the following slide.

Non-GAAP financial measures

Non-GAAP Earnings Reconciliation for the year ended December 31, 2020		
(Dollars in millions, except EPS)	**Net Income**	**Diluted EPS**
GAAP as reported for the year ended December 31, 2020	$155	$1.72
Exclusion of certain trading losses	127	1.42
Tax effect (1)	(35)	(0.39)
Non-GAAP as reported for the year ended December 31, 2020	$247	$2.75

Non-GAAP Earnings Reconciliation for the year ended December 31, 2022		
(Dollars in millions, except EPS)	**Net Income**	**Diluted EPS**
GAAP as reported for the year ended December 31, 2022	$233	$2.60
Exclusion of released deferrals related to 2020	17	0.19
Tax effect (1)	(5)	(0.05)
Non-GAAP as reported for the year ended December 31, 2022	$245	$2.74

(1) Tax effects were determined based on the Company's full-year blended federal and state statutory tax rate

April 11, 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 060
Dated March 28, 2023

Request:

Refer to PGE press release "Portland General Electric announces Third Quarter 2022 Results", the Company states "The Company is increasing long-term EPS growth guidance from 4% to 6% from a 2019 base year to 5% to 7% EPS from a 2022 adjusted base year. Positive Request for Proposals (RFP) results and strong renewable development, grid investment opportunities, and load growth create a path to increase investments on behalf of customers."

a. Please provide electronic copies of external and internal company reports and/or financial analysis conducted by the Company prior to making this statement to investors.

Response:

OPUC Standard Data Request No. 24 Attachment A, slide 5 provides the 2023 Finance Plan, which is the basis for the long-term earnings guidance on the Third Quarter 2022 earnings call.

The long-term EPS growth guidance range is based on an adjusted 2022 EPS. PGE is using the final 2022 actual adjusted EPS of $2.74 for its long-term guidance range of 5% to 7% EPS growth.

August 11, 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 122
Dated August 4, 2023

Request:

Refer to UE 372 / PGE / 100 / Murtaugh – Cristea / 4 / Lines 2-3, “PGE also expects the energy storage projects listed above to enhance PGE's resource portfolio flexibility and support renewable energy resources integration.”

a. Please provide hourly dispatch information from energization of the Beaverton Public Safety Center (BPSC) and the Anderson Readiness Center (ARC).
b. Please provide a narrative description on how PGE dispatches the batteries located at the BPSC or the ARC, specifically how those batteries enhance portfolio flexibility and/or support renewable energy resources integration.
c. Please indicate if the BPSC or the ARC is connected at the transmission voltage level to PGE’s system.

Response:

a. Confidential Attachment 122-A provides the requested raw hourly dispatch information. Note that on the hourly dispatch value, negative is charging and positive is discharging.

b. The batteries at BPSC and ARC are 250 kW and 500 kW, respectively, and are primarily used to contribute to the company’s Frequency Response Obligation (FRO) and Contingency Reserve Obligation (CRO). Since renewable resources are variable energy resources (VERs), they contribute little or nothing to reliability in the form of Frequency Response or Contingency Reserve. As more of these resources are brought online, PGE must also bring online resources capable of providing critical ancillary services (e.g. FRO and CRO) to sustain reliability and comply with the NERC reliability standards.

   The batteries at BPSC and ARC are also used as Demand Response (DR) resources, enabling the company to better manage peak load and to reduce overall demand when energy prices are high. This flexibility in the bulk energy portfolio will better enable PGE to rely on an increasing supply of VERs.

c. Both BPSC and ARC projects are connected at the customer premise behind the meter, which is not transmission voltage level.

Attachment 122-A contains protected information and is subject to General Protective Order No. 23-039.

August 11, 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 123
Dated August 4, 2023

Request:

Does PGE consider a transmission project that is not a gen-tied to an underlying qualifying renewable energy resource to be an "associated transmission" project for purposes of RAC cost recovery?

a. Has PGE ever sought recovery of a transmission project that is not gen-tied to an underlying qualifying renewable energy resource through a RAC proceeding?

Response:

PGE objects to this request in that it calls for speculation. Without waiving said objection PGE states as follows:

It would depend on the purpose of the transmission investment whether a project that is not gen-tied to a qualifying renewable energy resource would be considered "associated transmission." As PGE stated in PGE Exhibit 2700, in this rate case, PGE is only seeking a definition of "associated energy storage" and is not proposing a definition for "associated transmission" for purposes of the RAAC.

a) No.

August 11, 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 127
Dated August 4, 2023

Request:

Is the Wheatridge battery configured to be charged by the solar physically located at Wheatridge? Can the wind facility, or power from outside of the Wheatridge facility, be used to charge the Wheatridge battery?

a. Please provide hourly operation information for the three phases of the Wheatridge Facility (Solar, Wind and Battery Storage) from commercial operation to July 2023 in an electronic spreadsheet.

Response:

The Wheatridge battery is configured to be charged only by solar at the site. The battery cannot be charged by the Wheatridge wind facility or grid due to the interconnection agreement, the contractual terms which require the battery to be charged by the solar facility to qualify for investment tax credits to provide the full economic value under the contract for customers and by project design.

a) Confidential Attachment 127-A provides the requested data for Wheatridge I, PGE-owned wind hourly generation. Confidential Attachment 127-B provides the requested data for the PPA-portion, Wheatridge II Solar, Wind, and Battery Storage.

Attachments 127-A and B contain protected information and are subject to General Protective Order 23-039.

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 Portland General Electric Company's (PGE or the Company) Reply Testimony on some issues in this proceeding. Specifically, I will discuss the following:

II. Employee Discount
III. Rate Spread – Schedule 115 and 118
IV. Rate Spread – Schedule 118 Customer Cap
V. Rate Spread
VI. Rate Design
VII. Income-Qualified Bill Discount (IQBD) Program

II. EMPLOYEE DISCOUNT

Q. What is CUB's recommendation on PGE's employee discount program?

A. CUB continues to recommend that the Commission reduce PGE's employee discount from 25% to 5%.

Q. How does PGE respond to CUB's proposal?

A. PGE argues that peer energy utilities offer a similar discount to PGE. The Company also reasons that employee discounts are prevalent in other industries. PGE argues that there is no link between the income qualified discount program and the employee discount program. The Company also argues that the

Commission has already ruled on this issue for PGE in UE 197, and that CUB has offered nothing new on this subject.

Q. What is CUB's response to PGE's argument that PGE's competitors offer an energy discount, and therefore, PGE needs to maintain its employee discount level?

A. CUB has already sufficiently rebutted PGE's arguments in opening testimony, and PGE has offered no new evidence to justify retaining this discount program. Regarding this argument specifically, CUB stated that we would seek similar reductions in the employee discount for peer energy utilities in future general rate cases, if this reduction was adopted by the Commission. Therefore, PGE's argument that it must maintain its employee discount level would be moot should CUB's proposal be adopted across its peer Oregon utilities.

CUB also challenges the assertion that this discount is valued by PGE employees. PGE has hundreds of employees who live outside of PGE's service territory in either Oregon or Washington and is still able to retain these employees without providing them with any discount on their electric service. Further, CUB raised in opening testimony that we have found no evidence that the employee discount is a major benefit that allows PGE to attract and retain employees.[1] Despite the opportunity, PGE has still failed to provide any evidence that this program is a major driver in PGE's ability attract and retain employees.

[1] UE 416 – CUB/300/Gehrke/14, lines 5-9.

Q. What is CUB's response to PGE's argument that employee discounts are common in other industries (i.e., apparel, telecom, automotive)?

A. CUB's proposal was to reduce the employee discount to 5%, not eliminate the employee discount. Eligible PGE employees would still have a discount on utility service under CUB's proposal, which addresses PGE's concern.

Q. What is CUB's response to PGE's argument that there is not a link between the income-qualified bill discount program and the employee discount program?

A. PGE is incorrect—there is a very clear link. The Commission is tasked with setting just and reasonable rates at an overall level and both discount programs bear on the overall level of rates PGE collects from cost-of-service customers. CUB finds it unreasonable to offer a larger discount to PGE's employees than to low-income Oregonians. CUB has put evidence on the record that PGE's employees are well compensated and do not require a 25% discount on PGE service. Further, as discussed, both programs are discounts whose cost impact are borne by PGE's customers. The link is that while PGE used to only offer one discount, the Company now offers two. All other customers will face rate pressure from the existence of both discounts, and it is therefore reasonable for the Commission to consider the cumulative impact of both when assessing the reasonableness of PGE's legacy employee discount program.

Q. What is CUB's response to PGE's argument that this issue has already been ruled on in UE 197?

A. While the Commission has addressed this issue in the context of UE 197, it does not mean that it cannot re-examine the issue many years later. Standard adjustments are constantly re-reviewed in the general rate case cycle. CUB acknowledges that it is challenging the status quo around employee discounts. Despite PGE's posturing, PGE is not the only party who is able to advance proposals in a general rate case. In every general rate case, PGE has made rate proposals that challenge the status quo around PGE's ratemaking. For example, PGE has repeatedly tried to make changes to how the PCAM operates despite clear prior Commission rulings on the topic.

CUB believes that it is appropriate to ask the Commission to reduce the employee discount level at this time. In the medium term, CUB expects that customers will experience significant price pressure due to PGE's business plan around decarbonization and HB 2021. CUB's proposal will help mitigate price pressure immediately in this case, and reduce unnecessary expenses related to employee discounts as prices increase for all customers going forward.

III. RATE SPREAD – SCHEDULE 115 AND 118

Q. Please summarize CUB's testimony on this topic.

A. In Opening Testimony, CUB recommended using projected residential usage rather than 1000 kWh to estimate the per bill charges for Schedule 115 and 118. In Reply Testimony, PGE supported CUB's recommendation. CUB continues to recommend that the Commission adopt its proposal.

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

A. Residential customers have been overpaying for Schedule 115 and Schedule 118 due to a rate spread error. This is a straightforward tariff change, that will allow for a more accurate amount of revenue to be collected from residential customers. Additionally, the Commission has also adopted this tariff change for PacifiCorp. CUB's tariff change will result in a more accurate cost being assigned to residential customers.

IV. RATE SPREAD – SCHEDULE 118 CUSTOMER CAP

Q. What is CUB's position on the Schedule 118 customer cap?

A. CUB recommends that the Commission remove the customer cap for Schedule 118.

Q. What was Portland General Electric's response to CUB's proposal to remove the cap?

A. PGE disagrees that the cap should be removed because large electricity industrial customers would experience "bill impacts that are not indicative of their size."[2] PGE indicated that they are open to expanding the customer cap for Schedule 118.[3]

Q. What cap cost cap exists for Schedule 115?

A. This rate schedule provides funding for the Oregon Energy Assistance Program (OEAP). This program provides valuable energy assistance for communities in PGE's service territory. Schedule 115 has a per site cap of $500 dollars per site. Ratepayer funding for the OEAP has increased over time. Due to the Schedule 115 customer cap, the largest energy customers receive bill protection from any costs increases in this program. Other customers classes pay higher prices under

[2] UE 416 – PGE/2600/Macfarlane – Pleasant/39/Lines 2-3.
[3] UE 416 – PGE/2600/Macfarlane – Pleasant/39/Lines 4-6.

Schedule 115 to cover costs that are not recovered due to larger customer's cap in Schedule 115.

Q. What cost cap exists for Schedule 109?

A. Schedule 109 pays for energy efficiency funding. Customers larger than 1 aMW and self-directed non-residential are capped on customer contributions to this rate schedule. Energy efficiency programs provide long-term system benefits by lowering overall electricity demand, which reduces the need to invest in new utility resources. Energy efficiency also diversifies utility resource portfolios and can be a hedge against uncertainty around the costs of meeting customer system load. Investments in energy efficiency provide system benefits, which benefit all customers. Other customers classes pay higher prices under Schedule 109 to cover larger customer's customer cap in Schedule 109.

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

A. CUB understands the sensitivity to avoid large rate increases for a specific customer class. However, large energy users already receive rate protections to address this exact concern for Schedule 115 and 109 on PGE's system. CUB is not seeking changes to the cost cap for Schedule 115 and 109 but would note that large customer classes are already protected from other costs on PGE's system.

Q. What was Staff's position on the Schedule 118 cost cap in opening testimony?

A. Staff recommends this cap be revisited at such a time that enrollment, costs, or other relevant metrics or design elements of the IQBD have changed to warrant an adjustment to this feature.[4]

[4] UE 416 – Staff /600/Scala/44.

Q. What is the issue with the Schedule 118 cost cap?

A. As costs increase under Schedule 118, Schedule 89 and 90 contributions will remain flat due to the cost cap. This means that if costs were to increase under Schedule 118 and the $1000 cap was upheld, no additional costs associated with the low-income qualified discount program would be spread to Schedule 89 and 90.

Q. What is the current amount being recovered in rates for Schedule 118?

A. During the 2023 rate year, Schedule 118 is collecting **(Start Confidential)** [redacted] **(End Confidential)** from all customers.

Q. What are the projections of Schedule 118 costs?

A. Future costs of Schedule 118 will vary based on enrollment numbers and the level of discount provided. CUB projects that based on the various proposals in this general rate case the cost of Schedule 118 could vary from **(Start Confidential)** [redacted] **(End Confidential)** dollars in 2024 based on parties' proposal in Opening Testimony. CUB asks the Commission to remove the Schedule 118 cap, so that all customers can contribute to the costs of reducing residential energy burden.

Q. What is the impact of removing the customer cap on Schedule 118?

A. CUB produced Exhibit 501, which compares the rate spread of removing the Schedule 118 cap to maintaining the $1000 customer contribution cap under various revenue requirements for Schedule 118.

V. RATE SPREAD

Q. What is CUB's position on overall rate spread?

A. CUB recommends that the Commission allocate costs as detailed in Exhibit 502. CUB recommends allocating costs consistent with the rate spread detailed in PGE's Reply testimony, along with CUB's recommend changes to Schedule 118 and 115.

Q. Did PGE respond to AWEC's proposed adjustments to the generation cost study?

A. Yes. PGE opposed two components of AWEC's proposal: reducing the battery resource's ELCC to 57% and removing the capacity value from the cost of wind energy. PGE accepted the following items:

- Modifying battery salvage cost from -5% to -0.5%.
- Removing wheeling costs from battery calculations.
- Increase overnight capital costs from $1195/kW to 1215/kW.
- Reduce the battery ELCC to 80%.

Q. What did AWEC recommend on the capacity value from the cost of wind energy?

A. In its initial filing, PGE uses a wind resource as the marginal cost of energy for capacity valuation purposes. PGE assumes that 100% of the value of the wind resource is associated with energy. AWEC proposes to remove the capacity value of wind from the marginal cost of energy.

Q. What is the impact of AWEC's modification to the marginal cost of energy?

A. AWEC modifications detailed in opening testimony decrease the cost of energy and increases the cost of capacity. If adopted, AWEC's modification would result in price pressure on residential and small commercial customers, while reducing price pressure on large energy users.

Q. What is CUB's position on AWEC's recommendation change?

A. CUB disagrees with AWEC's recommendation. In UE 394 and UE 335, wind resources have been included as part of the blended marginal energy cost without removing the capacity value of wind from the marginal energy cost.

Q. What type of resource is a wind facility?

A. Wind resources are not built to meet a capacity need because these resources are not dispatchable resources like natural gas turbines or energy storage. Instead, wind resources are built to meet energy needs for the utility. PGE does not rely on wind resources to provide capacity on high load days. On high load days, PGE's Power Operations assumes that no wind generation resources will be available during either the real-time operating window of super-peak hours or during the entire day.[5]

Q. What is CUB's response to the Company's changes to the customer marginal cost study?

A. CUB does not oppose PGE's reallocation of customer marginal cost study detailed in the Company's reply testimony.

Q. What is CUB's position on using cost-of-service study?

A. The Commission has historically used long-run marginal costs to guide utility cost allocation. Cost of service study results should serve as a guide to the allocation of revenue requirement between customer classes, not as the sole determinant. This case represents a major change in PGE's allocation of generation costs. For the first time, Portland General Electric is modeling marginal generation costs using emissions-free generation resources, which is a significant change. AWEC's

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[5] UE 416 – PGE/300/-Schwartz – Outama – Cristea-/-25.

proposed allocation would reduce the marginal cost of energy, increase the cost of demand, and would result in dramatic cost swings between customers classes in future rate cases. Even without AWEC's proposed allocation shift, the initial rate request is significant for weather-sensitive customers, including residential, irrigation, and small commercial. CUB advocates for incrementalism when making changes to marginal cost for generation and argues that AWEC's proposed change is too significant to be adopted at this time.

Q. What is CUB's proposed cost allocation?

A. CUB recommends that the Commission adopt CUB Exhibit 502 for allocating costs. The proposed rate spread uses PGE's marginal cost model from Reply testimony and allocates costs with CUB's recommend changes to Schedule 118. To provide a holistic view on rates, CUB's rate spread includes rate changes that have or expected to occur during the year.[6] In 2023, PGE has updated the costs associated with Schedule 152 "Major Cost Recovery" to include the increased costs of the COVID-19 pandemic and the refund associated with the Boardman Deferral. In 2023, PGE has also increased rates under a new rate Schedule 153 for a Community Benefit and Impacts Advisory group. To be conservative, CUB has included the Schedule 118 costs with no expansion of the bill discount program, in combination with modeling the rate spread impact of Schedule 118 having no customer cap. CUB has changed the rate spread for Schedule 118 to include a residential per bill charge based on 795 kWh per bill usage.

VI. RATE DESIGN

[6] CUB's rate spread table does not include the costs associated with Schedule 151, the Wildfire Mitigation Cost Recovery AAC, because it has not been approved by the Commission.

Q. What is CUB's position on residential rate design changes?

A. CUB is open to engaging in settlement on outstanding residential rate design issues. Rate design has been discussed through the course of the proceeding in UE 416. CUB would like to respond to Staff's proposal regarding the Residential Exchange Program (REP) under Schedule 102.

Q. What was Staff's proposal?

A. Staff proposed to allocate the REP credit on either a per-customer basis, rather than on a per kWh basis. As an alternative recommendation, Staff proposes instead to cap the credit on 2,000 kWh per month.

Q. What is CUB's position on Staff's proposal to change how Schedule 102 costs are allocated within the residential class?

A. After reviewing how the Staff's proposal interacts with other rate design changes such as increasing the customer charge, CUB is open to either of Staff's proposals.

VII. INCOME-QUALIFIED BILL DISCOUNT PROGRAM

Q. What is CUB's recommendation?

A. The interim IQBD program as it stands does not address the additional price pressure that energy burdened customers are due to face in the general rate case. CUB supports CEP and CAPO's efforts to expand discount tiers for the most affected residential customers. CUB offers an alternative proposal to expand the IQBD program for the Commission that would balance cost impacts to the remainder of PGE's customers, with a recognition that PGE's IQBD program may be altered further in the ongoing investigation. CUB supports CEP, CAPO, and Staff's recommendation for a low income needs assessment (LINA).

Q. How is PGE's IQBD program currently structured?

A. PGE's interim program implemented a three-tiered approach to low-income discount design. The Company uses state median income (SMI) as a qualifier for a bill discount. For households earning between 60% and 45% SMI, PGE's customers fund a 15% discount on the total monthly bill. For households earning between 45 and 30 percent SMI, these households receive a 20% discount on the total monthly bill. For households earning between 30% SMI and less, these customers receive a 25% discount on the total monthly bill. This program was implemented on an interim basis.

Q. What was CEP's position on this topic?

A. CEP advocated offering one or two more tiers with steeper discounts, available to those at 10-25% SMI. CEP also proposed that up to a 90% discount be provided in the IQBD. CEP encouraged PGE to perform a LINA.

Q. What did CAPO position on this topic?

A. CAPO recommends changing the bill discount program to be calculated to keep a customer under 6% energy burden.[7]

Q. What was Staff's position on this topic?

A. Staff recommended that PGE should either increase the level of discounts using either increases within its existing three-tier structure or by addition of a fourth discount tier greater than 25 percent. Staff also asked PGE to conduct a LINA.

Q. What did PGE offer on this topic?

[7] UE 416 – CAPO/100/Springer/36, lines 12-15.

A. In response to stakeholder feedback, PGE proposed to create a fourth tier which would provide a 40% discount for households at or below 15% of SMI. In reply, PGE appeared to offer this program to mirror programs offered by NW Natural.

Q. Is it necessary for PGE to mirror NW Natural's program?

A. No. NW Natural and Portland General Electric have different service territories, products, and customers. While the two energy utilities do have an overlap in service territories, it is not necessary to align to two discount programs.

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

A. CUB appreciates PGE offering a fourth tier. However, CUB would like to offer the following discount program to offer additional relief.

CUB Discount Level	
Discount Tier	Discount Level
Tier 0 (0%-15%)	60%
Tier 1 (15%-30%)	25%
Tier 2 (30% to 45%)	20%
Tier 3 (45% to 60%)	15%

Q. What are the goals of CUB's proposal?

A. CUB's IQBD proposal is an attempt to give additional discounts to the most highly energy burdened customers in PGE's service territory in anticipation of significant price changes resulting from this general rate case. The discount level is not adequate to completely address the energy burden for low-income customers, but it will likely help alleviate impacts from this general rate case while the larger investigation into IQBD programs can move forward. CUB's proposal will completely offset potential price increases for the 0-15% discount tier, while addressing existing energy burden under current prices. CUB asks the Commission to prioritize relief towards low-income customers with the highest energy burden.

Q. What is an estimate of the cost of CUB's proposal?

A. CUB projects that the cost in 2024 would be **(Start Confidential)** [redacted] **(End Confidential)**.[8]

Q. What is CUB's estimate of the cost of PGE's proposal?

A. CUB projects that the estimated costs of PGE's 40% discount proposal from Reply Testimony to be **(Start Confidential)** [redacted] **(End Confidential)** in 2024.

Q. What is CUB's position on a LINA?

A. CUB finds tremendous value to having a LINA being performed on PGE's service territory. It is also CUB's position that a LINA would be helpful to stakeholders when evaluating approaches and tradeoffs around a permanent program.

Q. What does CUB want for a low income needs assessment?

A. Other peer utilities have completed Oregon LINAs, which have been helpful in informing expansion of the low-income discount programs. CUB would like the Company to complete the LINA by January 1st, 2025. CUB also recommends that the LINA be a collaborative process between stakeholders (Company, Staff, and Advocates) with parties working together towards a designing a LINA, not as a Company led process.

Q. Does this conclude your testimony?

A. Yes.

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[8] CUB would like to note that IQBD projections are estimated, while actual costs can vary based on actual enrollment and load.

CUB Exhibit 501 is Confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 22-039.

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UE 416– CERTIFICATE OF SERVICE

I hereby certify that, on this 22nd day of August, 2023, I served the **Confidential Testimony of the Oregon Citizens' Utility Board** in docket UE 416 upon the Commission and each party designated to receive confidential information pursuant to Order 23-039 through a secure, encrypted attachment to an e-mail.

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