Portland General Electric Company
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portlandgeneral.com

August 14, 2024

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

RE: UE 435 – In the Matter of Portland General Electric Company, Request for a General Rate Revision

Dear Filing Center:

Enclosed for filing today in the above-reference docket is Portland General Electric Company's (PGE) Reply Testimony and Exhibits.

It has been served on all parties of record.

If you have any questions, please feel free to contact me at (503) 464-7488. Please direct all formal correspondence and requests to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

Jaki Ferchland

Jaki Ferchland
Senior Manager, Rates and Regulatory Affairs

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Reply Testimony Overview

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Jacquelyn Ferchland
Christopher Liddle

August 14, 2024

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I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Jaki Ferchland. My position is Senior Manager of Revenue Requirement, Regulatory Affairs. My witness qualifications appear at the end of PGE Exhibit 200.

My name is Chris Liddle. I am Senior Director, Risk Management and Assistant Treasurer. My qualifications can be viewed at the end of PGE Exhibit 600.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide an overview of PGE's reply testimony, reiterate key drivers for the 2025 rate review filing and provide an outline of our response to parties opening testimony. We emphasize the critical investments we have undertaken on behalf of our customers, while simultaneously reiterating the importance of addressing affordability concerns. In addition, we address a couple of overarching themes we have identified within the parties' testimonies, which we believe merit due consideration by the Commission when reviewing this case.

Q. Please provide an overview of this general rate case thus far.

A. In PGE's direct testimony, filed on February 29, 2024, we outlined the circumstances and critical activities necessitating this rate case request following the Commission's resolution of PGE's prior rate case, Docket UE 416 (UE 416). We discussed the substantial, ongoing changes in our operating environment that continue to shape our strategy and essential investments to deliver safe, reliable, and affordable electric service as part of a cleaner and more resilient energy future. We summarized the forecasted January 2025 customer price change and described key investments in significant battery storage facilities, reliability, and resiliency enhancements throughout our Transmission & Distribution (T&D) system, which drive the need for the price increase. Additionally, we discussed actions taken and practices integrated into our business operations to manage costs and protect the affordability of electricity for our customers. We also presented policy proposals intended to better align key regulatory mechanisms with resource adequacy requirements while potentially mitigating the frequency of future rate cases.

Q. Please restate the key elements of your filing.

A. Throughout the period spanning from the end of 2023 through 2024, PGE has undertaken substantial and necessary investments predominantly in our transmission and distribution system, as well as initiatives to increase the availability of clean capacity for power generation. We are currently bringing into service two utility-scale battery energy storage systems, one scheduled to begin serving customers by the end of 2024 and the other by mid-2025. The totality of the investments made in this case are focused on addressing regulatory and statutory compliance requirements, fixing and replacing aging or defective assets, and meeting the evolving needs of our customers. As a result of these efforts, approximately 75% of PGE's request in this rate review is related to new capital investments.

Limited increases in operating and maintenance expenses are being driven by inflationary needs,[1] as well as necessary increases to cover insurance premiums, FITNES[2] routine vegetation management, and the implementation of a virtual power plant.

It is important to highlight that the investments and operational requirements we are currently facing were not accounted for in PGE's previous rate review. This necessitated the filing of a new rate review to ensure that our costs of service accurately reflect the expenses

[1] Note that inflation could be addressed with load growth in years where investments match depreciation, however, all load growth is returned when a rate review filing in made.

[2] Facilities Inspection and Treatment to the National Electric Safety Code (FITNES).

required to meet our customers' expectations for safe and reliable power delivery. Each of these elements, from infrastructure upgrades to regulatory compliance measures, plays a vital role in our commitment to providing customers with safe, reliable service.

Q. Have any settlements been achieved in this case to date?

A. No, but we remain committed to collaborating constructively with all stakeholders involved in this case. PGE is open to achieving a fair and reasonable settlement that appropriately balances the interests of all parties through continued good-faith negotiations.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II – Balancing Cost Recovery with Affordability
- Section III – Addressing Themes in Parties Testimony
- Section IV – Conclusion
- Section V – Outline of PGE Reply Testimony

II. Balancing Cost Recovery with Affordability

Q. How did PGE come to the decision to file for this rate review?

A. We genuinely acknowledge the difficulties our customers have faced in recent years, particularly at the beginning of this year, and we understand the concern surrounding increases in utility prices. We are committed to collaborating with stakeholders to find thoughtful and balanced solutions during this period of significant transition within our industry, coupled with challenging economic conditions. We have established and proposed several programs and pathways to make utility prices more affordable, especially for low-income customers, and discuss those efforts in more detail in PGE Exhibit 1200 – Affordability Programs and Proposals. In the face of the energy industry's transformation, PGE is striving to meet multiple imperatives—to promote affordability, serve society's growing need for electricity, move to increasingly clean and sustainable sources of power to meet decarbonization mandates, and reliably and safely provide service in the face of increasing extreme weather events. PGE has been doing the work on behalf of our customers to strengthen and innovate our transmission and distribution system and drive the clean energy transition over the past year. These investments were not part of the last rate review because they were outside the test year of that case. As discussed further in PGE Exhibit 1100 – Capital Planning and Business Model, maintaining a reasonable financial position in the face of these new investments without filing for this rate review to seek recovery would be untenable. This was a challenging decision, but one we ultimately deemed necessary.

Q. Does the fact that PGE filed a rate case after the conclusion of the prior rate case and in the context of other recent price increases, demonstrate a lack of commitment to energy justice or awareness of customer impact?

A. No. As mentioned above, the decision to file this rate case was a challenging one due to our need to both serve our customers and maintain a sound financial position. This rate review also allows us to collaborate with parties on proposals related to energy justice and affordability programs, as discussed in detail in PGE Exhibit 1200. Energy Justice involves fairness and equity in the development, distribution, and consumption of energy by balancing the needs for economic growth, environmental sustainability, and social equity so that no group bears an unfair share of the negative consequence of energy policies. The transition to clean energy resources supports a more equitable and sustainable energy system by helping to mitigate impacts of pollution and climate change, which can disproportionally impact vulnerable communities. We view energy justice as intrinsic to our company's future operations.

While applying an energy justice lens is crucial, it does not render other regulatory principles irrelevant. Energy justice cannot be achieved solely by focusing on a desired price outcome for a subset of customers. The investments reflected in this rate case are focused on helping achieve essential outcomes for customers in terms of reliability, flexibility, customer control, and clean energy. We need to address energy justice concerns while keeping with the regulatory principles of cost causation and recovery to which we operate as a regulated utility. Please also see PGE Exhibit 1200 for our detailed response to Staff and stakeholder recommendations regarding energy justice and PGE's recently completed Energy Burden Assessment.

Q. Could you please elaborate on the specific investments included in this rate review and the critical importance of these investments for PGE's operations and service to customers?

A. The investments PGE is undertaking are critical. Recent events, such as the heat waves experienced this summer, the multiple wildfires, and the ice storm earlier this year, have highlighted the continued and increasing importance of a resilient and robust system. Continued investments are essential to fortify our infrastructure and enhance our ability to withstand such occurrences. Furthermore, we must remain committed to driving the clean energy transition while maintaining reliable power delivery for our customers.

In this case, over 85% of the investments in this filing are aimed at addressing regulatory or statutory requirements, repairing or replacing aging or damaged assets, or accommodating customer growth and evolving customer needs. Additionally, the two new battery storage assets PGE is investing in help to address the capacity shortfall resulting from the increasing integration of renewable energy sources into our system. This clean capacity is critical for achieving both PGE’s and the State’s clean energy goals.

Q. Should PGE be reducing its investment as suggested by one party?

A. While it may be tempting for parties to advocate to reduce investments or expenditures when facing price increases, failing to continue investing in our system can compromise our ability to maintain a reliable and resilient infrastructure capable of withstanding climate impacts and supporting the clean energy transition. We have an obligation to serve our customers, and that requires making thoughtful and prudent investments in our system. Notably, no party questions the prudence or need of the capital projects PGE has included in this rate review filing.

Q. How does PGE envision working with stakeholders moving forward to find the best balance for risk and reward for the utility?

A. Given the fundamental alignment of mission and key goals that exist between PGE, stakeholders, and the Commission, we believe continued collaboration and cooperation among the parties will lead to identifying the reasonable balance of risks and benefits between customers and PGE, as well as the regulatory framework to achieve this balance. We also seek outcomes that address the challenging circumstances we and many other utilities in the region and across the country are currently facing, allowing us to successfully implement the clean energy future, and to ensure that our vital service remains safe, reliable, secure, and affordable for all.

Q. Has PGE made any updates or changes to its filed request in this case?

A. Yes. Acknowledging the comments received from customers and stakeholders and to concentrate on the primary purpose of this case, which is the recovery of new investments made to serve customers that were not included in the last rate review, PGE has elected to withdraw both its Investment Recovery Mechanism (IRM) and associated storage policy proposals from this case. Further, we have reduced our requested Return on Equity (ROE) in this case to 9.65%, which remains at the lower end of proposed ROEs for utilities across the country. Also, we made several reductions, as shown in the updated revenue requirement presented in PGE Exhibit 1300 – Revenue Requirement, reflecting our review of the testimonies provided by the parties.

Finally, PGE had initially proposed to amortize the full value of the investment tax credits (ITCs) associated with battery storage projects to customers over the next five years on a front-loaded declining basis. However, this approach garnered objections from various parties in this proceeding. In consideration of our commitment to delivering optimal value to our customers and aligning with the proposals put forth by the parties, we are now proposing to amortize the ITCs to customers within the revenue requirement over the useful life of each respective project, based on the actual values we will receive for the ITCs.

Q. Do these updates affect PGE's requested price impact?

A. Yes. They result in a net reduction of $18 million to PGE's originally filed price request. This reduces the total price change for 2025 by 0.6%, lowering the request in this filing to 6.3%. PGE has a separate annual power cost update in Docket UE 436 to review our 2025 forecast of power costs which are a pass-through to customers and for which the company does not earn a return. Other supplement schedules are expected to experience a decrease in 2025.

Q. Has PGE changed the timing of the price change of this case?

A. We understand the concerns raised about the timing of price changes and the potential challenges it may pose for our customers. While we are maintaining our proposed January 1, 2025 effective date for this case, we highlight that altering this timing is not a straightforward task for PGE. We operate on a calendar year financial planning model, which makes it challenging to abruptly decouple changes to our base rates from our budgeting, accounting, and planning processes.

However, we have carefully considered the testimony highlighting the difficulties associated with price changes during this time of year. We recognize the potential impact on our customers, and we are actively exploring alternate pathways that could allow for a transition to a different rate review timeline in the future. Our goal is to find solutions that align with our financial and operational requirements and the needs and well-being of our customers.

Q. How important is it for PGE that customer prices be set at the actual cost-of-service?

A. As a fully integrated electric utility with no significant lines of business outside of our regulated operations serving electricity customers, it is of paramount importance that our pricing accurately reflects the costs associated with providing service to our customers.

Q. How do you balance the need to set cost-of-service prices at an appropriate level that accurately reflects prudent spending and investments, while also addressing concerns of affordability for customers?

A. This is one of the most important and challenging questions that is facing our industry today.[3] Balancing the need for cost-reflective pricing with affordability concerns is a complex challenge that requires a thoughtful approach. On one hand it is important to consider the affordability of utility services, particularly for low-income and vulnerable customers. Rate increases can place a burden on households with limited financial resources, potentially leading to energy insecurity and other socioeconomic challenges.

On the other hand, it is essential to set prices that accurately reflect the prudent investments and costs incurred by the utility to provide safe, reliable, and sustainable service to customers. This ensures that the utility can recover its prudently incurred expenses and maintain financial stability, enabling it to continue making necessary investments in infrastructure, technology, and clean energy initiatives with low-cost access to capital. To balance these priorities, a multi-faceted approach is often necessary.

[3] *See* https://www2.deloitte.com/us/en/insights/industry/power-and-utilities/rising-electricity-costs.html

Q. Could you elaborate on the specific components or strategies that comprise the multi-faceted approach you mentioned for balancing cost-reflective pricing and affordability concerns?

A. Yes. First, we must strive for operational efficiency and cost optimization to minimize expenses and keep rates as low as possible without compromising service quality or infrastructure investments. PGE is committed to continuously enhancing its operational efficiency and proactively identifying cost-saving opportunities. For example, PGE sought to find a way to maintain strong insurance coverage despite growing premiums and a shrinking market which resulted in a more cost-effective solution.

Second, targeted assistance programs, such as low-income energy assistance, bill payment plans, and energy efficiency initiatives, can help mitigate the financial burden on vulnerable residential customers while still enabling the utility to recover its prudently incurred costs. We are committed to collaborating with our partners in the Community Benefits and Impacts Advisory Group (CBIAG) and through other channels to identify the most balanced and effective approach to these programs and offerings.

Third, additional tools may be needed to help align the utility's revenue with its actual costs to maintain cost-reflective pricing. Although we have withdrawn our proposals on the Investment Recovery Mechanism (IRM) and associated storage in this case to streamline the proceedings and be responsive to parties, we maintain our belief that appropriately designed regulatory mechanisms are necessary to mitigate the need for frequent rate reviews and ensure that rates accurately reflect a fair and reasonable representation of the cost of service.

Finally, stakeholder engagement and collaborative decision-making processes involving consumer advocates, policymakers, and other relevant parties can help identify equitable solutions that balance the interests of the utility, customers, and broader societal goals.

Ultimately, achieving a balance between cost-reflective pricing and affordability requires a comprehensive approach that considers the utility's financial sustainability, customer affordability concerns, and broader societal objectives such as energy justice and environmental sustainability.

III. Other Items in Parties' Testimony

Q. What other items do you want to address in this overview?

A. We would like to address three overarching themes we have seen within the testimonies of the parties participating in this case. The first is the parties' efforts to turn PGE's predominantly capital driven case into an O&M case by attempting to relitigate UE 416, and second is the number of duplicative proposals we have seen. Third, parties make statements regarding regulatory lag and erroneously comment that PGE is unwilling to incur "any" regulatory lag.

Q. Why is it important for you to address these challenges in this overview?

A. We discuss these three issues here because they are not confined to any single topical area but are interwoven throughout the extensive opening testimony of the parties. We respectfully disagree with the methodologies employed by the parties and aim to provide support against their approach. We highlight these three matters upfront to ensure that the Commission is mindful of these issues when reviewing the remainder of our testimony and gives them appropriate weight and consideration.

Q. How are parties approaching this rate review regarding the specific requests made by PGE?

A. The parties' approach to this general rate review appears to be an attempt to reframe a capital driven case as an O&M case, primarily aimed at revisiting the O&M increase from the UE 416 outcome. While they have inherently acknowledged the value of the capital investments made for customers making no claims of imprudence, they appear reluctant to bear the associated costs, thereby attempting to reduce the previously established O&M expenses instead.

Q. Can you illustrate how parties appear to be making this effort?

A. PGE has requested O&M and other revenue in this case of $61.2 million. Prior to any adjustment for duplicative items, parties are proposing adjustments to O&M of $168.7 million. This represents a proposed decrease of over 275% to PGE's O&M request.

While the parties make some proposals seeking to fundamentally alter the way rate base is calculated, they have otherwise only proposed minimal reductions to rate base – which we would note is not for the imprudent spending on any capital project. Basically, despite this being a capital driven rate review filing, parties have cut PGE's O&M request by over 275% but have only requested to reduce PGE's rate base by just a fraction of this amount.[4]

Such a drastic reduction in O&M funding would undermine our ability to retain and attract skilled personnel essential for the safe and reliable operation of our utility infrastructure. Insufficient staffing resources could hinder our ability to respond promptly to service disruptions, perform timely maintenance activities, and ensure adherence to the regulatory requirements governing our industry.

Q. How are parties seeking to relitigate the O&M outcome of UE 416?

A. In their testimony, two parties suggest that PGE should compare its 2025 Test Year forecast to PGE's 2023 actuals, instead of PGE's UE 416-based 2024 budget. While the traditional approach in rate case analysis is indeed to compare the test year to a base year of actuals, the unique circumstances of this case warrant consideration. PGE's 2024 budget, derived from the concluded UE 416 proceeding represents the most up-to-date and comprehensive information available for comparison purposes.

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[4] This value does not include proposal to alter how PGE calculates rate base, which is not a matter of prudence or perceived overspending.

Moreover, PGE's 2023 regulated earnings and financial performance, which was well below our authorized ROE of 9.5%, should be factored into any analyses that seeks to compare to 2023, but was not.

Q. PGE filed this case. Is it not PGE who seeks to relitigate multiple issues?

A. No. That has been a misrepresentation made in this proceeding. PGE has only revisited one issue that was previously addressed – the request to define "associated storage" for the purposes of the renewable adjustment clause to be inclusive of stand-alone storage. PGE has made multiple attempts over many years to gain clarity on this important definition. We continue to believe that this is an appropriate and reasonable use of the renewable automatic adjustment clause. PGE's willingness to engage in collaborative efforts with stakeholders in various proceedings to reach balanced settlements should not preclude the consideration of this issue in the future.

We would also note that Staff seeks to re-examine their "mismatched rate base" calculation, in addition to a nearly full-relitigation of O&M. Although Staff renewed their proposal, PGE is withdrawing its associated storage proposal from consideration in this case, which is discussed further in Exhibit 1700 - Production.

Q. Isn’t PGE relitigating ROE?

A. No. We disagree with the assertion that requesting a new ROE in this case constitutes a ‘relitigation.’ The underlying facts and circumstances that led to the determination of a 9.5% ROE in UE 416 have undergone significant changes since that decision. Contrary to their position that PGE should not have altered its ROE, parties have acknowledged changes to PGE’s cost of debt. Given the ROE and debt cost are linked, both must be reevaluated due to the dynamic economic environment. We would also note that this position of the parties is inconsistent with their own historical approach to ROE, which we discuss further in PGE Exhibit 1800 – Cost of Capital.

Q. What other concerns do you have regarding the proposed adjustments made by parties to PGE's O&M?

A. We would like to draw attention to a number of instances of duplicative and/or overlapping cost reductions proposed by the Parties. While we acknowledge that the parties do not coordinate their intended proposals, we have also noticed duplicative/overlapping reductions made within parties' own set of proposals. This is accomplished by suggesting broad cuts to certain cost categories, followed by additional line-item adjustments targeting the same areas. To ensure a thorough and accurate review of the numerous proposals aimed at reducing PGE's O&M expenses, we are highlighting identified instances of potential double-counting, whether occurring between parties or within a single party's proposal. Table 1 provides a list of these instances.

Table 1
Duplicative Adjustments

Labor

Staff reduction to entire labor	$ (34,081,945)	Duplicative of each other
AWEC reduction to entire labor	$ (34,238,543)	
Line-item reductions to same category		
Virtual Power Plant - Staff	$ (2,500,000)	Duplicative to AWEC and/or Staff's overarching category reductions
TE UM 2033 Budget Match - Staff	$ (920,000)	
EV Field Operations - Staff	$ (920,000)	
Key Customer Managers - AWEC	$ (700,000)	

Incentives

Staff Reduction to incentives	$ (3,668,322)	Duplicative of each other
AWEC Reduction to incentives	$ (2,978,990)	
CUB Reduction to incentives	$ (10,796,000)	

Non-Labor O&M - A&G

AWEC reduction to entire A&G	$ (4,585,715)	
Line-item reductions to same category		
Directors' Fees and Expense - AWEC	$ (3,275,875)	Duplicative to AWEC's overarching category reduction
Revolver Fees - AWEC	$ (2,157,244)	
Margin Net Interest - AWEC	$ (1,220,696)	
Broker Fees - AWEC	$ (133,318)	
Casualty Insurance - Staff	$ (5,606,769)	
Property Insurance - Staff	$ (2,149,000)	
Office Supplies - Staff	$ (1,780,000)	
Memberships - Staff	$ (301,984)	
Meals & Entertainment - Staff	$ (142,608)	

Non-Labor O&M - Distribution

AWEC reduction to entire Distribution	$ (4,290,307)	
Line-item reductions to same category		
Routine Vegetation Management - Staff	$ (6,171,000)	Duplicative to AWEC's overarching category reduction
Utility Asset Management - Staff	$ (5,886,000)	
Virtual Power Plant - Staff	$ (1,500,000)	

Non-Labor O&M - Customer

Staff reductions to Customer Service	$ (2,000,000)	Duplicative of each other
AWEC reductions to Customer Service	$ (5,253,818)	
Staff reductions to Customer Accounts	$ (2,000,000)	Duplicative of each other
AWEC reductions to Customer Accounts	$ (2,598,317)	
CUB's reduction to Customer Billing	$ (8,451,698)	

Non-Labor O&M - Generation

AWEC reductions to entire Generation	$ (5,812,649)	Duplicative of each other
Custer County Impact Fee - Staff	$ (2,000,000)	

Q. What is PGE's concern regarding statements that PGE is unwilling to accept *any* regulatory lag?

A. The assertions made demonstrate a concerning lack of understanding regarding the mechanics of regulatory lag associated with capital investments. Parties seem to be approaching this matter from a unilateral perspective, overlooking the interplay between the various components that contribute to regulatory lag. Moreover, it is noteworthy that no party sought to obtain relevant information through discovery to determine the extent of regulatory lag that PGE has experienced and continues to experience.

Q. How much regulatory lag is PGE experiencing?

A. Since January 2022, PGE has under-recovered approximately $150 million as a result of regulatory lag on capital investments. Additional discussion regarding regulatory lag is included in PGE Exhibit 1100.

Q. Does PGE have a request of the Commission regarding the issues identified here?

A. Yes. We respectfully request that, in determining fair and reasonable rates, the Commission carefully evaluate the most recent and relevant information. Furthermore, we urge the Commission to recognize the capital-driven nature of this case and assess it through that lens, while giving due consideration to the potential existence of duplicative or overlapping proposals resulting in increased proposed cost reductions. Additionally, we request that the Commission take into account the significant regulatory lag that PGE has experienced and continues to experience before determining how much more we should absorb. It is crucial to consider the potential adverse impacts of further exacerbating regulatory lag, which could undermine our ability to effectively execute critical capital investments on behalf of our customers.

IV. Conclusion

Q. Please restate the essential points of your testimony.

A. PGE understands the challenges that many of our customers have faced, particularly as our community emerged from the COVID pandemic and in the face of extreme events that have created hardships for many customers. We understand the concerns surrounding increases in utility prices and the potential burden it may place on households. Filing this general rate review was a necessary step to recover over $1.2 billion in investments made since the previous rate review. These investments are critical for enhancing the resilience of our system, driving the clean energy transition, and ensuring compliance with regulatory requirements.

While PGE recognizes energy justice as a fundamental component, we believe that a balanced approach is essential to uphold prudent cost recovery principles and maintain the sustainability of our vital services. Over $900 million of the proposed investments are aimed at repairing or replacing aging assets, meeting regulatory obligations, accommodating customer growth and evolving needs, and incorporating clean energy storage facilities. Reducing these investments could potentially compromise the reliability of our system and hinder progress in the clean energy transition, which would ultimately be detrimental to our customers.

In our efforts to strike a balance between cost recovery and affordability, PGE proposes a multi-faceted approach. This includes operational efficiency measures to minimize unnecessary expenses, targeted assistance programs for vulnerable customers, potential new approaches for cost recovery, and collaborative engagement with stakeholders. Notably, we have withdrawn certain proposals, such as the Investment Recovery Mechanism and the definition of "associated storage", and reduced our proposed ROE to 9.65%, to streamline the scope of the case and address concerns raised by parties. The cumulative impact of the changes PGE has made result in an $18 million or 0.6% reduction in total customer prices, this reduces PGE's request in this filing to 6.3%.

Additionally, we raise concerns that other parties are attempting to reframe this as an O&M case, thereby revisiting the outcome of the previous rate case as well as the presence of duplicative and overlapping cost reduction proposals from various parties.

Q. Is there anything else you wish to address?

A. Yes. In Section V, we have provided an outlined of the remaining pieces of supportive reply testimony.

V. Outline of Reply Testimony

Q. Please provide reference to other reply testimony PGE is submitting.

A. The following provides a high-level outline to PGE's reply testimony responding to issues raised in opening testimony by Staff and other parties:

Table 2

Exhibit	Summary
1100 – Capital Planning & Business Model	Witnesses Josh Kliever and Christopher Liddle discuss PGE's capital program and the efforts PGE takes to select appropriate and necessary investments each year to serve customers. They also discuss PGE's business model, the different ways regulatory lag can impact a utility, and PGE's prices effective date.
1200 – Affordability Programs and Proposals	Witnesses Kristen Sheeran and Jake Wise discuss PGE's comprehensive approach to affordability and address comments and proposals made by parties related to affordability, IQBD design, and procedural equity. They also respond to concerns expressed about bill transparency as well as public comments. Finally, they respond to proposals to address rate shock through rate caps.
1300 – Revenue Requirement	Witnesses Greg Batzler and Stephanie Meeks address multiple proposals made by parties impacting PGE's revenue requirement. Notably they address proposals to calculate PGE's rate base using either method that mismatches utility plant and depreciation, or one that uses an average over a historic test year.
1400 – Compensation and Corporate Support	Witnesses Anne Mersereau, Ryan Van Oostrum, and Greg Batzler speak to the continued need to address compensation holistically when addressing proposals made by parties. They also respond to proposals made regarding information technology investments, insurance and other topics related to administrative and general expenses.
1500 – Customer Service and Transportation Electrification	Witnesses John McFarland and Elyssia Lawrence discuss proposed reductions to customer service and customer accounts, specifically addressing the continue value of PGE's key customer managers. They also address proposals from parties on transportation electrification.
1600 – Production	Witnesses Debbie Powell and Brian Clark address proposals made by the parties regarding non-labor generation expense, the Constable and Seaside battery energy storage projects, the diesel particulate filter project, and fleet replacement investments. They also address PGE's proposed tracking mechanisms for the Constable and Seaside projects.
1700 – Transmission and Distribution	Witnesses Kellie Cloud, Franco Albi, and Kevin Putnam respond to parties' proposals regarding T&D non-labor expense, including routine vegetation management, FITNES expenses, and virtual power plant. They also address proposals for three capital projects and T&D capital contingencies. Finally, they discuss PGE's January storm response.
1800 – Cost of Capital	Witness Josh Figueroa, a Brattle consultant specializing in return on equity responds to different proposals and comments regarding PGE's proposed ROE. Witness Christopher Liddle addresses PGE's capital structure and cost of debt.
1900 – Marginal Cost of Service	Witnesses Rob Macfarlane and Casey Manley address proposals to alter PGE's generation and customer marginal cost of service studies.
2000 – Pricing	Witnesses Rob Macfarlane and Chris Pleasant address parties' positions on the residential basic charge, commercial time of use, and the load following credit. They also address issues regarding rate spread and propose that net variable power costs remain in a separate schedule on an ongoing basis. Lastly, they address TE line extension allowances.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Capital Planning and Business Model

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Josh Kliever
Christopher Liddle

August 14, 2024

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I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Josh Kliever. I am the Director of Financial Planning and Analysis at PGE. My qualifications are included at the end of this exhibit.

My name is Christopher Liddle. My position is Senior Director, Risk Management and Assistant Treasurer at PGE. My qualifications are included at the end of Exhibit 600.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to concerns and proposals raised by the Staff of the Public Utility Commission of Oregon (Staff), the Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) regarding PGE's overall capital spending program and proposed capital tracking mechanism, where the Parties' issues are unrelated to specific capital projects. As part of this discussion, we address Parties' comments regarding PGE's overall capital investment levels, the role of regulatory lag and PGE's price effective date.

Notably, despite extensive commentary on PGE's capital program, the Parties have identified only a limited number of specific concerns related to the actual investments made by PGE on behalf of our customers. The proposed adjustments by the Parties specifically tied to identifiable capital investments are addressed in the relevant testimonies.

Q. Please provide an overview of the topics you are addressing.

A. Our testimony is organized into two sections:

- First, we delve into the driving forces behind PGE's capital spending program. We explain the primary drivers behind PGE's capital spending program, the controls PGE utilizes to manage and control costs, and how these efforts serve customers. Contrary to

CUB's characterizations, PGE's corporate culture reflects a technology-neutral approach to decarbonization and electrification and a realistic understanding of the costs necessary to provide essential services to customers. As we discuss in more detail below, no party disputes the pressing need for PGE to invest in its system to safely and reliably serve customers—both in the immediate term and to enable a decarbonized future. Under a cost-of-service regulatory paradigm, PGE's effort to recover the costs of such prudent investments is both reasonable and appropriate.

- Second, we speak to PGE's business model. We look to the regulatory compact and the cost-of-service model that PGE follows to set customer prices, and we discuss the importance of this model for PGE. We then clarify the role of regulatory lag in PGE's ability to adequately invest in crucial infrastructure. In this section, we respond to Parties' characterization of PGE's actions as seeking to "eliminate all regulatory lag."[1] Despite the Parties' commentary, we show that PGE is actually incurring sizable quantities of regulatory lag on its investments. This is because needed investments are substantially outpacing depreciation, resulting in significant under-recovery of actual costs. In this environment, and recognizing Oregon's cost-of-service paradigm, updates are necessary to ensure that rates are "fair and reasonable."[2] Failing to address substantial cost recovery shortfalls would jeopardize PGE's financial health, its credit rating, and its ability to attract the capital needed for long-term provision of service. Finally, we speak to PGE's historic use of a calendar fiscal-year business model and the challenges we will

[1] CUB/100, Jenks/68.

[2] ORS 756.040(1) "Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility . . . and for capital costs of the utility, with a return to the equity holder that is (a) Commensurate with the return on investments in other enterprises having corresponding risks; and (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."

face to move to a timing that will disconnect changes in customer prices from PGE's financial model.

II. PGE's Capital Program

Q. Please summarize PGE's overall approach to capital spending and the key drivers behind PGE's investment levels.

A. PGE's approach to capital spending reflects the needs of our customers. Specifically, PGE's increased capital spending is driven by crucial infrastructure upgrades associated with broad regional and industry changes including (a) increased pressures on safety and reliability from growing wildfire and storm risks, as well as (b) ongoing decarbonization and electrification efforts that are driving a transformation of the electric system. These investments are not just needed for clean capacity and renewable resources, but also for the infrastructure to deliver this energy to homes and businesses. These investments are essential to ensure that PGE can safely and reliably serve customers now and into the future.

Q. What concerns do Parties raise about PGE's capital program?

A. Both Staff and CUB raise concerns regarding PGE's overall level of capital investment, asserting that PGE has failed to adequately prioritize and limit capital spending.[3] CUB also argues that PGE (a) has an "all of the above" corporate culture when it comes to investing;[4] (b) lacks adequate capital spending controls;[5] and (c) is focused on serving shareholders instead of customers.[6] As demonstrated by the substantial record in this case, and as we explain in detail below, these claims are simply untrue.

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[3] CUB/100, Jenks/36; Staff/200, Scala/18.
[4] CUB/100, Jenks/50-51.
[5] *Id.* 45.
[6] *Id.* 33-34.

A. Overall Capital Investment Levels

Q. Please describe how PGE develops capital investment levels.

A. The capital development process involves collaboration between various departments within PGE, including finance, engineering, and operations. PGE also engages with stakeholders through the Integrated Resource Plan (IRP) and the Distribution System Plan (DSP) process. Many factors are considered when determining near-term and long-term investment levels, such as:

- **Regulatory Requirements** - PGE must comply with regulations set by federal, state, and local authorities. These regulations often dictate certain investments, such as those related to safety, environmental standards, and reliability.
- **Infrastructure Needs** - PGE assesses the condition and capacity of its existing infrastructure. This includes evaluating the age of equipment, the need for upgrades, and the expansion of capacity to meet growing demand.
- **Technological Advances** - Investments in new technologies that improve efficiency, reliability, and environmental performance. PGE may allocate capital for smart grid technologies, renewable energy integration, and energy storage systems.
- **Customer Demand and Growth Projections** - Anticipating changes in customer demand, such as population growth or increased use of electric vehicles and electrification drives increased infrastructure and capacity needs.
- **Financial Health and Funding –** PGE's financial health, including its ability to raise capital through debt or equity, affects its capital plans. PGE balances the need for investment with maintaining affordability, financial stability and credit ratings.

Q. Does PGE consider customer affordability within its capital planning process?

A. Yes. PGE considers customer affordability when setting its capital expenditure levels. As a regulated utility, PGE must and does prioritize safety, reliability, and affordability, while meeting all necessary legal and regulatory obligations. While the question of affordability is detailed extensively in Exhibit 1200 – Affordability Programs and Proposals, below are some of the ways in which customer affordability impacts PGE's capital planning:

- **Cost-Benefit Analysis** - When planning for large strategic capital projects, PGE conducts cost-benefit analyses to evaluate the economic impact on customers. This includes assessing the long-term benefits of investments, such as improved reliability or safety, against the immediate costs to customers as appropriate for justification.
- **Rate Impact Considerations** - PGE aims to minimize the rate impact of its capital projects on customers. This can involve spreading the costs of large projects over time, seeking cost efficiencies, and prioritizing projects that provide significant value relative to their cost.
- **Stakeholder Engagement** - PGE engages with customers and other stakeholders through the IRP and DSP processes to understand their concerns and preferences. Although price impacts are not a part of these processes, feedback from stakeholders helps the utility align its capital spending with customer expectations and affordability.
- **Financial Planning and Forecasting** - PGE uses financial models to forecast the impact of capital spending on customer rates. This helps the utility plan its

investments in a way that aligns with customer affordability while meeting regulatory and operational requirements.

- **Efficiency and Cost Control** - PGE continually seeks ways to improve efficiency and reduce costs in its capital projects. This includes leveraging new technologies, optimizing processes, and negotiating favorable terms with contractors and suppliers.

Q. Did PGE provide information on the specific capital projects comprising the recovery request in this case?

A. Yes. In addition to PGE's Direct Testimony, PGE responded to extensive data requests from Staff, CUB and AWEC, which included more than 2,000 pages of information specifically concerning PGE's capital projects and capital investment process.[7]

Q. Does CUB address any specific capital investment presented for cost recovery in this case, or otherwise suggest that PGE's capital projects in this case are imprudent, premature, or unneeded?

A. No. CUB does not address the prudence, timing, or need for any of PGE's specific capital investments. However, CUB does address the prudence of PGE's *prospective* investment in a new transmission line, despite the fact that this project is not included for cost recovery in this case.[8]

Q. Does CUB nonetheless propose an adjustment concerning PGE's overall capital program levels?

A. Yes. Reflecting an admittedly "different" approach, CUB decides not to focus on PGE's actual costs incurred to provide service.[9] Instead, CUB focuses on speculative forecasts of PGE's

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[7] PGE response to Staff DR No. 231, 233, 235-253, CUB DR No. 6-7, and AWEC DR No. 16
[8] CUB/100, Jenks/53.
[9] *Id.* 4.

future investment levels,[10] claims that these forecasts reflect an "unsustainable business model," and argues that PGE should therefore be penalized with a $10.8 million reduction in employee incentive compensation, which is also discussed in Exhibit 1400 – Compensation and Corporate Support.[11]

Q. Does CUB realistically depict PGE's future capital investments levels?

A. No. There are two basic issues with CUB's forecast capital spending levels.

First, they are incorrect. PGE's capital plan and associated spend will reflect the results of its 2023 RFP, future IRPs, and DSPs. Simply escalating historical trends is not a fair or reasonable representation of future capital plans and targets.

Second, CUB's projections are irrelevant to this proceeding. PGE does not—and cannot—seek prospective Commission approval for future investments in this case. Rather, PGE seeks to recover the costs associated with prudent investments made to provide safe and reliable service to customers. These are known, measurable investments subject to substantial scrutiny and review in this contested proceeding. If any of PGE's future investments are, in CUB's opinion, imprudent, then CUB may assert such a position when cost recovery is sought.

Q. CUB also states that "PGE is more transparent about its capital spending plans with investors than it is with customers and PUC stakeholders."[12] Is this a fair assessment?

A. No. CUB appears to assume that PGE inappropriately classified capital spending plans as confidential in this case. CUB's assumption is misplaced. PGE is a publicly traded company and is subject to various Securities and Exchange Commission regulations intended to avoid selective disclosure of financial information. As such, forecasts regarding total capital

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[10] *Id.* 41.
[11] CUB/100, Jenks/54.
[12] *Id.* 36 .

spending present material financial information. Until this information has been unilaterally shared with investors, it must be kept confidential. Where information has already been released publicly to shareholders, the values are appropriately non-confidential. PGE hopes that this clarification resolves any confusion concerning the confidentiality of PGE's capital spending forecasts.

Q. Do you have any overarching responses to CUB's complaints concerning PGE's capital spending levels?

A. Yes. We recognize that PGE's capital investment levels have increased. These investments, as we have explained here and throughout this proceeding, are prudent and necessary to serve customers safely and reliably, and consistent with legislative and regulatory obligations. PGE works hard to constrain the amount of capital spending to a reasonable escalation, and indeed delays needed investments as long as reasonably possible in an effort to control cost increases. Yet the cost-of-service remains just that—the costs necessary to serve customers. PGE welcomes specific feedback from CUB, Staff, and other stakeholders regarding what aspects of PGE's investments they believe may be excessive. CUB's decision not to engage in the specifics of our financial realities is concerning. This disconnect from the application of cost-of-service is particularly troubling given that CUB simultaneously urges PGE to take actions—such as increasing field crews,[13] revising outage software systems,[14] and reducing disconnections[15]—that would necessarily *increase* the cost of service.

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[13] CUB/100, Jenks/31.
[14] *Id.* 32.
[15] *Id.* 81.

Q. What is CUB's position concerning the traditional cost-of-service paradigm?

A. CUB appears to reject the central cost-of-service paradigm in utility regulation. While CUB seems to recognize that "the purpose of the rates that are set [in a general rate case] is . . . to set a price that is generally reflective of the utility's costs and can be expected to produce a reasonable return on a going forward basis,"[16] CUB urges the Commission to ignore assets in service when setting rates effective for January 1, 2025.[17] We note that CUB also endeavored to reject the entirety of this case out of hand, regardless of PGE's actual prudently incurred costs to provide service to customers.[18]

In sum, it appears that CUB recognizes the need for the investments PGE has made to serve customers yet rejects the need to recover such costs through rates. PGE recognizes that capital investment levels have increased. These investments, as we have explained here and throughout this proceeding, are prudent and necessary to serve customers safely and reliably, and consistent with legislative and regulatory obligations.

B. Corporate Culture

Q. What is CUB's concern regarding PGE's "corporate culture" as it relates to capital investments?

A. CUB claims that "PGE's corporate culture" consists of an "all of the above" approach to investing, citing three specific examples—none of which in fact demonstrate such an indiscriminate pro-investment culture.[19]

- First, CUB states that "PGE CEO used the phrase to describe PGE's investments to support transportation electrification in an interview with GreenBiz magazine" from

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[16] *Id.* 66.
[17] CUB/100, Jenks/65.
[18] CUB's Motion to Dismiss (Mar 14, 2024).
[19] CUB/100, Jenks/50-51.

2020.[20] In that interview, PGE's CEO was asked how new transportation electrification infrastructure will allow for bidirectional flow of energy in the future: "Are these technology solutions? Education solutions? How do you create a system for EVs to be a benefit?" Her response to this *transportation electrification question* indicated that all of these solutions are necessary for electric vehicles to benefit the grid:

> I think it's an all-of-the-above. As we look at the four major areas that are a challenge for the transformation of the transportation sector, *we're looking at price*, we're looking at the product and the availability of buses or cars that are electric, we're looking at customer awareness and we're also looking at infrastructure.[21] (Emphasis added.)

Plainly, her specific description, from four years ago, of PGE's "holistic" approach to an emerging initiative, transportation electrification, is far removed from CUB's generalities concerning PGE's overall collaborative approach to capital investments.

- Second, CUB refers to a shareholder earnings call from 2021, in which PGE's CEO was asked again about transportation electrification. The interviewer asked whether PGE's TE strategy includes "EV charging stations" or "new substations to deliver more electricity to various areas".[22] In response, she explained that tackling the transportation electrification transition involves both actions: "It will be additional cabling and infrastructure to get to charging stations and it will be charging stations in and of themselves."[23] This statement was not a broad characterization of

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[20] *Id.* 51.
[21] Karen Fehrenbacher, "10 questions on EVs for the CEO of Portland General Electric," Green Biz, Feb. 18, 2020, see https://www.greenbiz.com/article/10-questions-evs-ceo-portland-general-electric.
[22] PGE Earnings Call, June 30, 2021 see https://www.fool.com/earnings/calltranscripts/2021/07/30/portland-general-electric-company-por-q2-2021-earn/.
[23] *Id.*

"corporate culture," but merely appropriately recognized the multi-faceted nature of serving transportation electrification customer.

- Third, CUB refers to an interview with PGE's Senior Director of Clean Energy Origination and Structuring, in which he indicated that comprehensive decarbonization requires more than wind and solar: "We are supportive of all technology."[24] Far from urging widespread investment, his statement merely expressed a technology-neutral approach to achieving decarbonization goals for customers.

Q. Do any of the above examples support CUB's characterization of a "corporate culture that wants to invest in nearly everything"?[25]

A. Plainly, no. PGE's support for a resource-neutral and diverse approach to decarbonization is consistent with our commitment to safely and reliably serve customers using a least-cost, least-risk approach.

Q. What did PGE's CEO mean when she said, "at Portland General, we have an expression where we say, 'how to' versus 'why not'" in an interview with S&P Global?[26]

A. The quote is part of a larger response to a closing question from the interviewer asking PGE's CEO to describe the company's biggest challenge and biggest opportunity in 2024. Her full response was:

> Our biggest challenge is bringing everything together to make a difference and addressing the pace of change that our customers are asking of us, and it is absolutely our biggest opportunity. At Portland General, we have an expression where we say, 'how to' versus 'why not' – so we are leaning in,

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[24] Aaron Larson, "PGE Leans into an All-of-the-Above Strategy to Decarbonize Its Power System," Power January 23, 2024, https://live-powermag.pantheonsite.io/pge-leans-into-an-all-of-the-above-strategy-todecarbonize-its-power-system/.

[25] CUB/100, Jenks/50.

[26] S&P Global, Listen: National Grid, Portland General Electric CEOs share thoughts on the energy transition, April 5, 2024; *See* https://www.spglobal.com/commodityinsights/en/market-insights/podcasts/energy-evolution/040524-nationalgrid-portland-general-electric-future-challenges-energy-power.

> to meet our customers' needs, in a way that is unprecedented for us as a company.

In the full quote, it is clear the CEO's response to the question was centered on delivering what PGE customers want and need, with a focus on problem-solving rather than barriers. It reaffirms the appropriate alignment between PGE's business opportunity and the fulfillment of customers' needs – consistent with the regulatory compact – but in no way points to a corporate culture that discourages employees from asking tough questions about spending strategies or individual spending decisions, as CUB suggested in their testimony. Simply put, PGE seeks to identify and prioritize "how to" serve customer needs. PGE's CEO speaks publicly with many industry peers, trade associations, government bodies, community leaders, customers, and media on a variety of industry topics and issues. These remarks and expressions are standard and depend on the specific questions and forums.

Q. Does CUB point to specific decarbonization-related investments that demonstrate this alleged over-investment?

A. No. While CUB claims that it "is not opposed to decarbonization," CUB states that a more appropriate approach for PGE "involves setting priorities" and "managing its budget[.]"[27]

Q. Does CUB state what it believes these priorities should be?

A. No. CUB reiterates that PGE must have "strategic thinking," which "requires recognizing what is essential, what is unnecessary, what is immediate, and what can be delayed."[28]

Q. Does CUB indicate what it believes are essential investments that should be deployed immediately, as opposed to unnecessary investments that can be delayed?

A. No. CUB does not engage with any of the details of PGE's essential investments.

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[27] CUB/100, Jenks/51-52.
[28] *Id.* 52.

C. Capital Review and Control Systems

Q. What is CUB's position concerning PGE's capital review and control systems?

A. CUB claims that it "has found little evidence" to show that PGE's capital review and control systems "effectively constrain or control capital spending."[29]

Q. Does PGE have clear and effective capital review and control systems?

A. Yes. As outlined in numerous project specific and overall capital process data request responses and as provided in PGE Exhibit 211, PGE's capital review and control process includes multiple steps in the life of any capital project to ensure that costs are contained as much as reasonably possible. PGE's internal capital controls help prioritize competing investments within available funding. Capital plans and targets are necessary to support customer growth, capacity additions, wildfire mitigation, improvements to reliability, maintenance of current generating fleet assets, transmission upgrades and additions, technology to improve efficiencies and new customer programs, and to fund new assets associated with PGE's IRP and DSP filings.

Q. What problems do you see with CUB's claims that PGE does not manage its budget by considering whether to delay projects?

A. Where PGE has effectively controlled spending by delaying capital projects to future years, such projects are not presented for parties to review because no cost recovery is currently being sought. Thus, CUB's approach side-steps the traditional prudence review process, whereby parties evaluate investments actually made. Instead, CUB implicitly argues for a new form of review where PGE must demonstrate and document the costs *not actually incurred* in order to avoid disallowances to employee compensation.

[29] CUB/100, Jenks/45.

Q. CUB states that "PGE's goal is to spend in order to meet its target[.]"[30] How do you respond?

A. CUB appears to misconstrue PGE's basic budgeting process. PGE, like many utilities, aims to align its actual capital expenditures with its capital budget. During the annual capital planning cycle, PGE must prioritize projects within its budget target. With demand for capital exceeding target budgets, many projects are de-prioritized and delayed. These projects are still often necessary, however, and may be re-prioritized depending on a range of factors, including regulatory approvals, changing market conditions, and unforeseen events. Here are some points to consider:

- **Budget Management** - PGE develops an annual capital budget based on expected needs, regulatory requirements, strategic goals, and financial capabilities. The budget serves as a plan for capital expenditures, but actual spending can vary. Project controls and governance help ensure that our overall capital investment levels remain within the overall budget.
- **Project Execution and Timing** - The timing and completion of capital projects can impact whether PGE meets its target budgets. Delays, changes in project scope, material escalations, or accelerated timelines can lead to deviations from the budget. As project execution and timing changes, PGE will make strategic adjustments to other prioritized projects within the capital portfolio to meet its annual capital plan.
- **Regulatory Changes** - PGE may adjust its spending to comply with new regulatory requirements or constraints.

[30] CUB/100, Jenks/47.

- **Market and Economic Conditions** - Changes in the cost of materials, labor, and financing can affect PGE's ability to stay within its budget. For example, rising costs may lead to budget overruns, while cost savings might allow for under-budget spending.
- **Strategic Adjustments** - PGE may adjust its capital spending plans based on changing strategic priorities, such as shifts in customer demand, technological advancements, or sustainability goals.
- **Financial Considerations** - PGE must balance capital spending with maintaining financial health, including managing debt levels, credit ratings, and shareholder returns. This financial discipline can influence how closely actual spending aligns with the budget.

Q. CUB states that it is PGE's practice to "reallocate" money from one project to another if one project is delayed, in order to reach "capital spending targets."[31] How do you respond?

A. CUB's broad assertion is based on a comment that PGE made in the context of our distribution system—an area with significant need for reliability investments and a long backlog of crucial, customer-serving projects. During PGE's annual capital planning process, there continues to be more demand for prudent and high priority capital investments identified than what can fit within the capital targets set. Projects that are below the funding line for one year are delayed to future years on a multi-year capital plan. Throughout the operating year, when one specific project experiences a delay, PGE staff does not automatically underrun its annual capital plan. Rather, as projects experience execution and timing changes, PGE will make strategic

[31] CUB/100, Jenks/47.

adjustments within the capital portfolio, such as pulling future year projects that were below the funding line into the current year, to balance and meet PGE's multi-year capital plan. On a monthly and quarterly basis, PGE continuously re-prioritizes urgently needed projects to ensure that progress continues—even where one specific project may encounter uncontrollable delays. PGE has clearly demonstrated through the robust record in this case that the costs incurred to serve customers were reasonable and prudent.

D. Capital Drivers and Benefits

Q. CUB claims that PGE's investments are designed to increase shareholder profits rather than customer benefits.[32] Is this correct?

A. We disagree with CUB's characterization. The investments we are making are necessary to maintain a safe, reliable, and modern energy system that benefits customers. While increasing shareholder value is certainly a consideration for any investor-owned utility, our primary focus with these capital investments is on meeting our regulatory obligations, complying with legislative mandates, and proactively upgrading aging infrastructure to enhance service quality and resilience for the customers we serve.

We firmly believe these investments provide tangible benefits to customers in the form of improved reliability, reduced outages, enhanced safety, and a more sustainable energy future. At the same time, we have a duty to our investors to manage the business prudently and earn a reasonable return on their investment, which allows us to access the capital markets to fund these critical infrastructure projects.

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[32] CUB/100, Jenks/34 (claiming that PGE's need for new capital investments means there will be "even higher profits in future years").

Q. CUB points to PGE's investor presentation as evidence that PGE is excessively focused on achieving shareholder returns at the expense of customer experience.[33] Do you agree with CUB's characterization of PGE's investor relations materials?

A. No. On the contrary, the shareholder presentation that CUB cites highlight PGE's focus on customer service: PGE has (1) been ranked as a Top 5 Utility in the United States for customer experience for the past three years – and ranked number one in 2024 – according to Forrester; (2) been in the top decile nationwide for Residential Customer Delight according to Escalent's National Energy Utility Benchmarking Study; and (3) has enrolled over 85,000 households in the Income Qualified Bill Discount Program—all while maintaining its national number one ranking renewable power program for the past 14 years, according to the National Renewable Energy Laboratory.[34] Meanwhile, PGE has been consistently under-earning its authorized ROE.[35]

Q. CUB claims that PGE's price increase is unnecessary because earnings are increasing. Is this correct?

A. No. CUB's characterization of PGE's historical earnings is incomplete and misleading. The investor presentation cited by CUB shows that PGE's overall 2023 GAAP diluted earnings per share was $2.33;[36] down from $2.60 in 2022;[37] which in turn was down from $2.72 in 2021.[38] PGE consistently underearns relative to its allowed ROE of 9.5% which has been partially driven by increased power cost volatility and regulatory lag associated with

[33] CUB/100, Jenks/33.
[34] CUB/109, Jenks/14.
[35] *Id.* 16.
[36] The referenced figures are not contained in CUB's cited Exhibit 109; rather, the correct materials are available here: http://investors.portlandgeneral.com/static-files/d75866e4-cceb-4516-a91b-44cd39fd5778.
[37] See April 28, 2023 First Quarter Presentation, available here: http://investors.portlandgeneral.com/static-files/490bb7af-a84d-4115-9d60-a64eb283c0d6.
[38] See April 28, 2022 First Quarter Presentation, available here: http://investors.portlandgeneral.com/static-files/7042651a-be71-4211-9fd1-c9f83ade16aa.

capital investments on behalf of customers. This persistent ROE underperformance continues to be a concern from PGE investors and rating agencies.

Q. What are the actual drivers of PGE's capital investment?

A. The actual drivers of PGE's capital investments include the following:

- **Inflation** – Higher inflation for transformers, conductor and other raw materials has continued to put additional cost pressure on PGE's capital investments.
- **Infrastructure Upgrades and Maintenance** – Investment in upgrading and maintaining infrastructure, such as power lines, substations, and generation facilities, to ensure reliable service and meet growing demand.
- **Transition to Renewable Energy** – Increased investment related to new wind (Clearwater), solar and battery (Constable, Coffee Creek and Seaside) investments. These investments support PGE's transition to reduce emissions and meet decarbonization mandates while decreasing net variable power costs associated with fuel costs for customers.
- **Regulatory Compliance** – Increased investment to comply with environmental regulations including upgrading generation facilities to support decarbonization, increased spend on distribution and transmission overhead line maintenance to comply with NESC regulations.
- **Technology and Modernization** – Investments in new technologies, such as smart grid, cybersecurity, advanced distribution management systems (ADMS) other technology to better manage the grid and enable new functionality for customers.
- **Customer Growth** – Increased spend on new substations and distribution capacity additions to support customer growth, increased spend to support municipality

projects including road widenings, new customer connects, increased transmission infrastructure investment to support constraints within PGE's service territory and improve reliability.

Q. Specifically, what capital additions is PGE seeking to include in customer prices through this general rate case?

A. Below is a table showing the total capital additions by functional class, excluding Clearwater, Constable, and Seaside. Clearwater will be included in customer prices through Docket No. 427. PGE is seeking tracking mechanisms, if needed, for both Constable and Seaside and detailed information regarding each project was included in PGE Exhibit 500 - Production.

Table 1
Capital Additions and Accumulated Depreciation by Functional Class

Functional Class	2024 In-Service	Depreciation	Net
Distribution Plant	$ 464,979,784	$ 172,781,422	$ 292,198,362
Transmission Plant	$ 229,792,047	$ 32,057,648	$ 197,734,399
Other Production	$ 155,053,396	$ 113,309,766	$ 41,743,630
General Plant	$ 110,220,733	$ 54,013,014	$ 56,207,719
Intangible Plant	$ 65,594,517	$ 88,554,762	$ (22,960,245)
Hydro Production	$ 42,369,295	$ 25,371,725	$ 16,997,570
Total	**$ 1,068,009,772**	**$ 486,088,337**	**$ 581,921,435**

Q. What kind of work is represented in the table above?

A. The capital projects included in this case fit into one of four categories: 1) Regulatory or Statutory Requirement, 2) Fix or Replace, 3) Customer Need, and 4) Strategic Business Need.

When examining projects in this case that are valued over $3 million, 40% were driven by regulatory or statutory requirements; 29% were driven by the need to replace or fix old or damaged assets; 24% were driven by customer demand; and 7% were driven by strategic business need.

Q. Please provide a detailed explanation of the investments PGE has undertaken this past year to warrant the need for this rate review.

A. Over the past year, PGE has been actively investing in the modernization and fortification of its transmission, distribution and generation infrastructure. This initiative involves the critical maintenance and enhancements of our wind and thermal plants, systematic replacement of aging power lines and poles with more advanced and resilient infrastructure, as well as the upgrade of substations and transformers to enhance their durability and performance. PGE has also been implementing new grid automation and monitoring technologies to bolster the reliability and efficiency of its operations.

Currently, PGE is in the process of completing the installation of two utility-scale battery energy storage systems, the Constable and Seaside projects. These systems will play a crucial role in supporting the integration of renewable energy sources into the grid, while also providing vital backup capacity to ensure a consistent and reliable power supply.

Through its transportation electrification program, PGE has been proactively building out electric vehicle charging infrastructure to accommodate the growing demand for electric vehicles. Furthermore, the company has been deploying smart grid technologies and advanced metering infrastructure to enable more effective demand management and optimize energy usage across its service territory.

Recognizing the critical importance of cybersecurity in today's digital landscape, PGE has been making strategic investments in state-of-the-art technologies to safeguard its systems and infrastructure against potential cyber threats and attacks.

These initiatives are essential for maintaining the safety, reliability, and resilience of PGE's electric grid, thereby ensuring the consistent delivery of high-quality services to its customers. The company firmly believes that delaying or postponing these critical projects would be detrimental to the long-term sustainability and performance of its infrastructure and operations.

III. Business Model

A. Cost of Service

Q. Please describe the basic foundation of regulated utility cost recovery principles.

A. The 'regulatory compact' is an established principle that grants utilities an exclusive franchise to provide service within a designated territory. In exchange, the utility's operations, costs, revenues, and rates are subject to regulatory oversight and approval. This legal framework ensures the utility meets its obligation to serve all customers within its service area at rates that cover prudent operating costs and allow a reasonable return on invested capital. The regulatory compact forms the basis for the cost-of-service ratemaking principles employed by regulatory commissions.

Q. What are the principles of setting cost-of-service rates?

A. Rates should reflect the costs incurred by the utility in providing electric service, and they should be designed to be fair and equitable for customers. Rates should support the financial health of the utility and be set at levels that are affordable for customers while ensuring that the utility can maintain reliable service and make necessary investment in infrastructure and technology. Further, rates should promote economic efficiency by sending price signals that reflect the true cost of providing electric services, encouraging conservation, innovation, and optimal resource allocation.

Q. How much of PGE's operations are regulated?

A. Approximately 95%. Unlike other electric utilities regulated by the Commission, PGE is an Oregon-based electric utility that exclusively serves retail customers within the state of Oregon. While PGE owns minor revenue-generating assets that are not part of its utility operations, such as leasing portions of the World Trade Center, we do not engage in other significant revenue-producing lines of business that could mitigate financial challenges within our regulated operations. For example, the challenge of significant under-recovery of prudently incurred investments.

Q. How can customer prices become disconnected from the actual costs of electric service?

A. The alignment between customer rates and the true cost of providing reliable electric service is a delicate balance influenced by numerous dynamic factors. Load growth, capital investments, inflation, and regulatory lag are just some of the variables that can cause rates to diverge from actual cost structure over time. It is crucial to recognize the implications of this potential disconnect and take proactive measures to maintain fair and sustainable rates.

For instance, if load is increasing while inflation remains stable, there may be an opportunity for prudent investments without immediately necessitating a rate case. However, if load is growing, inflation is low, but the utility does not make incremental infrastructure investments to serve new loads, customers are effectively overpaying for service. A rate case is needed to rectify this situation.

Conversely, in periods of stagnant or modest load growth coupled with significant inflation and/or substantial capital investment requirements, regulatory lag can become a pressing concern. Delaying rate changes in such circumstances can lead to detrimental under-recovery for the utility, jeopardizing its financial stability and ability to maintain and upgrade critical infrastructure. This, in turn, could compromise service quality and reliability for customers.

To uphold the principles of the regulatory compact and ensure fair, just, and reasonable rates for all stakeholders, it is imperative to proactively address these potential misalignments. Regular rate cases, based on thorough analyses of costs, investments, and changing market conditions, are necessary to maintain the delicate balance between customer affordability and the utility's ability to provide safe, reliable, and sustainable service now and in the future.

B. Regulatory Lag

Q. What are the Parties' positions concerning regulatory lag in this proceeding?

A. Staff claims that "eliminating any regulatory lag for new capital investment is PGE's paramount concern."[39] CUB similarly claims that PGE's goal is "to eliminate all regulatory lag."[40]

Q. What is regulatory lag on capital?

A. Regulatory lag reflects under-recovery of the financing costs on capital assets that are used and useful to serve customers. Specifically, regulatory lag comprises the difference between when the utility has placed a capital asset in service and the point when the utility can begin to recover the financing costs of the investment. During moderate investment periods, regulatory lag may be offset by ongoing depreciation of a utility's rate base.

Q. Is PGE currently experiencing regulatory lag for projects that entered service in 2023?

A. Yes. Approximately $100 million of additional capital came into service in 2023 that was not anticipated within the Docket UE 416, and therefore not included in rate base. PGE has already incurred more than a year of lag on these investments and will continue to do so until these investments are incorporated into rate base. Additionally, the total amount of net utility plant in service through the end of 2023 was over $800 million above amounts included in PGE's 2022 general rate case (Docket UE 394), which formed the basis for 2023 prices.

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[39] Staff/100, Beitzel/7.
[40] CUB/100, Jenks/68.

Q. Can you quantify the amount of regulatory lag PGE is experiencing on in-service projects during 2024?

A. Yes. Through June of 2024, PGE has already under-recovered $30 million due to regulatory lag on in-service projects not in customer prices. The full year under recovery on the assets in service through June will be approximately $65 million. This does not account for amounts placed into service through the remainder of this year, which will further increase under-recovery.

Q. How much regulatory lag on capital has PGE experienced since January 2022?

A. Since January 2022, PGE has under-recovered approximately $150 million due to regulatory lag on capital investments. As with the values provided for 2024, this represents the return on debt and equity costs and depreciation expense for in-service net utility plant not captured in customer prices.

Q. Given this information, is it accurate to claim that PGE is trying to eliminate all regulatory lag?

A. No. As we have explained, PGE is in a period that requires considerable new investment. The pace of this investment substantially outpaces depreciation—resulting in unacceptable levels of regulatory lag.

Q. What are unacceptable levels of regulatory lag?

A. Unacceptable levels of regulatory lag means that PGE's new investments far outpace offsetting depreciation on existing rate base.

Q. What are the impacts of unacceptable levels of regulatory lag?

A. Unacceptable levels of regulatory lag jeopardize PGE's financial health, its credit rating, and its ability to attract the capital needed for the long-term provision of service. To be clear, PGE's shareholders have already provided the capital necessary to serve customers. Under a cost-of-service regulatory model, PGE is responsible for recovering the costs necessary to reimburse investors, including a reasonable cost of capital. Where PGE cannot seek recovery for prudent investments, rates are not fair and reasonable, and we will be unable "to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[41]

Q. Could you please illustrate the difference between acceptable and unacceptable regulatory lag?

A. Chart 1 illustrates what happens when the utility invests at an amount approximately equal to depreciation over a period of a year. In this chart, the amount of rate base that customers are paying for in rates generally corresponds to the actual amount of rate base that the utility has invested:

[41] ORS 756.040(1).

Chart 1
Rate Base – Utility Investment Matches Depreciation

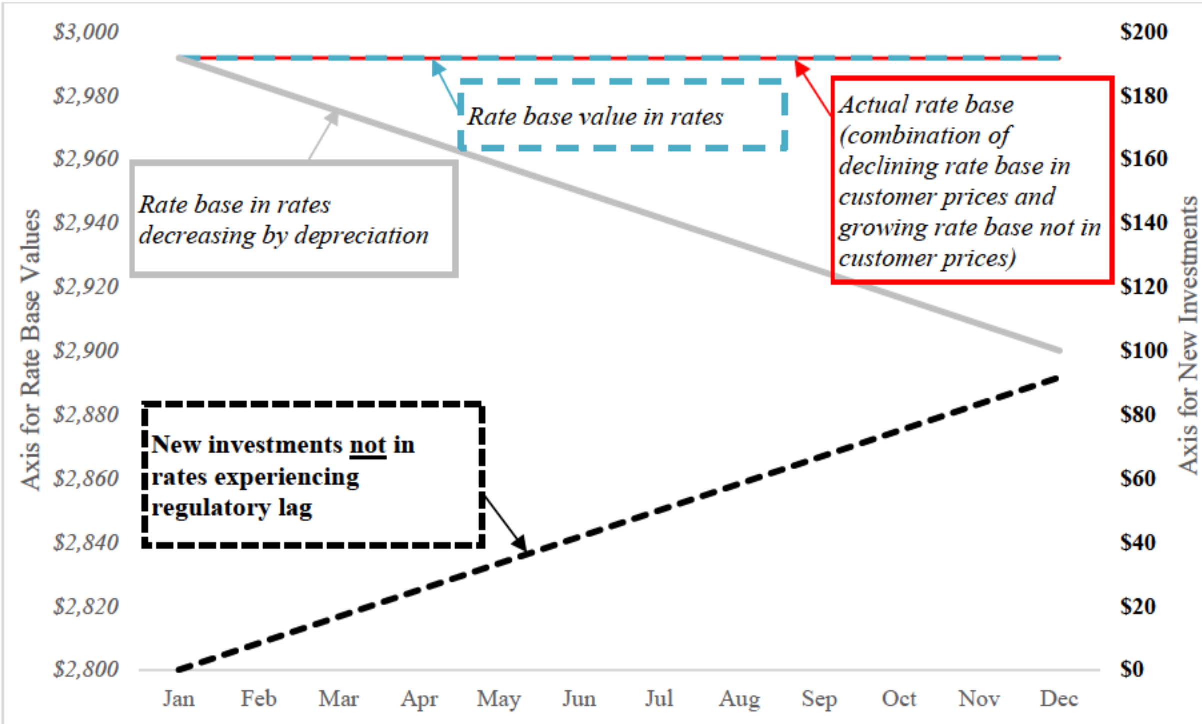
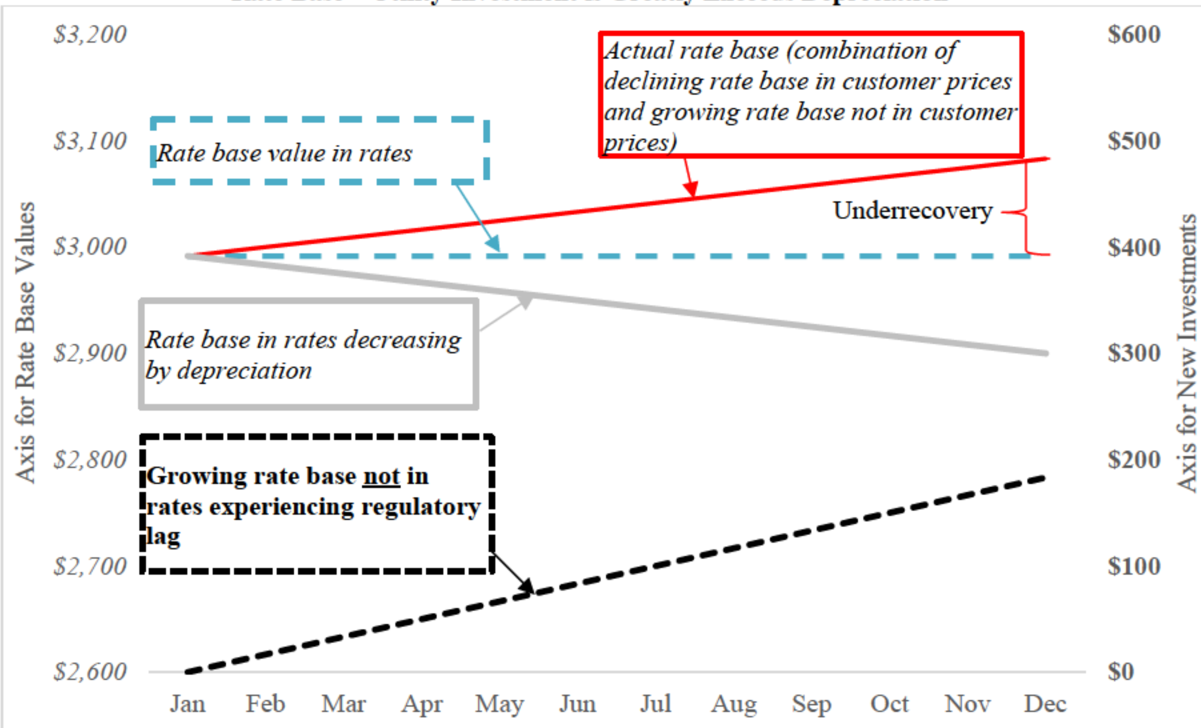


Chart 2 shows what happens when the utility needs to invest on an ongoing basis at a value that is higher than depreciation all through the year. As this chart shows, this results in a substantial mismatch between the capital costs incorporated into rates ("Rate Base in Rates") and the capital costs that the utility is actually incurring ("Actual Rate Base"):

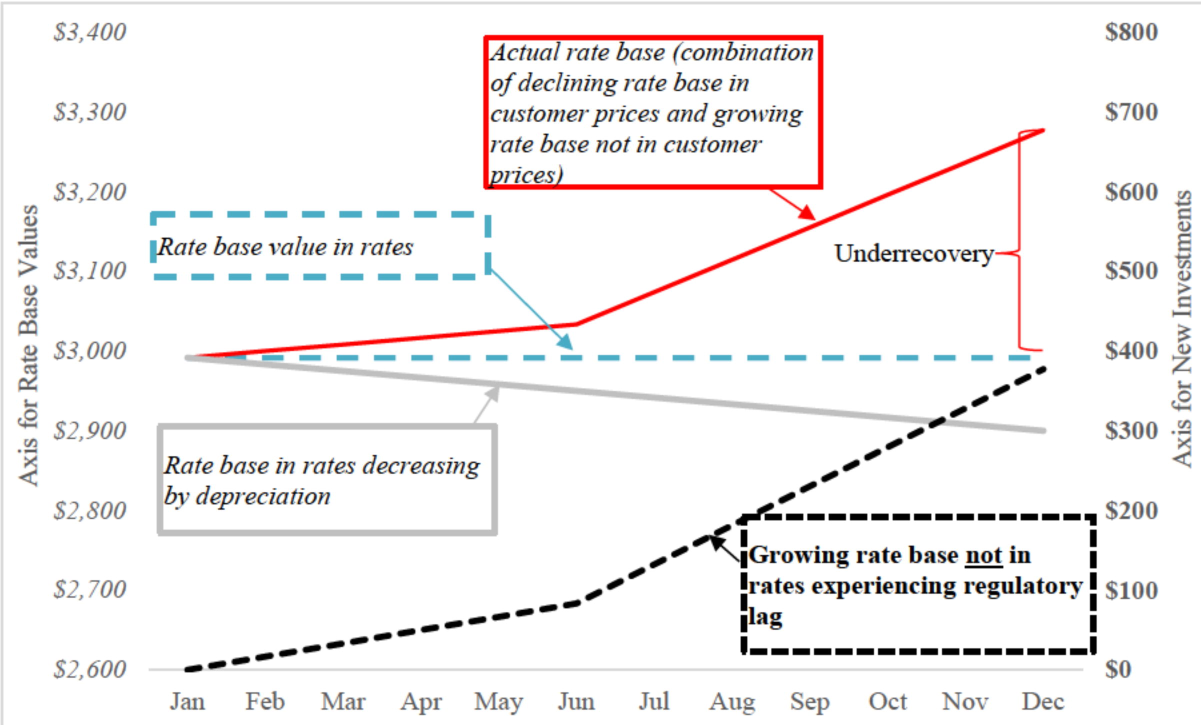
Chart 2
Rate Base – Utility Investment is Greatly Exceeds Depreciation



Here, the gap between Actual Rate Base and Rate Base in Rates shows that the longer PGE invests at amounts above depreciation, the more under-recovery of prudent investments grows.

Finally, Chart 3 shows what happens when the utility needs to invest on an ongoing basis at a value that is higher than depreciation and also experiences the addition of a single large asset mid-year.

Chart 3
Rate Base – Utility Investment Exceeds Depreciation,
And One Large Asset Addition



1 **Q. Which of the above three charts best reflects PGE's current reality?**

A. PGE's current reality is best reflected by Chart 3. Not only are we investing at a rate that substantially exceeds offsetting depreciation, but we are placing two new major, prudent, and vitally needed battery investments in service. PGE therefore seeks the opportunity to reflect our actually incurred costs in rates.

Q. CUB suggests that not allowing for significant regulatory lag essentially overcharges customers.[42] Is this true?

A. No. CUB's characterization assumes that depreciation always matches or exceeds ongoing investment levels. However, as shown above in both Charts 2 and 3, when investments substantially outpace depreciation, regulatory lag prevents us from having a reasonable

[42] CUB/100, Jenks/55.

opportunity to recover our prudently incurred costs of providing service. Looking at PGE's most recent SEC Form 10-Q, PGE's depreciation and amortization expense for the six months ending June 30, 2024, was $243 million compared to capital expenditures of $623 million.

Q. What amount of regulatory lag has been proposed by the Parties in this case?

A. Staff has stated that PGE should have waited "at least seven or eight additional months to file a new rate case[.]"[43] CUB does not specify what degree of regulatory lag it considers appropriate but appears to believe that *all* of PGE's incremental investments should be subject to perpetual regulatory lag until broader economic conditions change.

Q. Did either Staff or CUB address the economic impacts of regulatory lag?

A. No. Neither Staff nor CUB considered the impact of substantial and increasing regulatory lag on PGE's financial health, nor did they address the associated impacts on capital costs.

Q. What are the practical impacts of the Parties' approach to regulatory lag?

A. If there is no reasonable opportunity for investors to recover their capital costs, then the cost of obtaining future capital inevitably goes up to reflect that risk. Indeed, the extreme amount of lag proposed by the Parties could undermine PGE's ability to attract capital at all.

Q. Is there any indication that PGE's financial health might be threatened by such severe regulatory lag?

A. Yes. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

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[43] Staff/100, Beitzel/7.

[44] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Additionally, for the first time in over 10 years PGE has been placed on 'negative outlook' with one of its rating agencies—with the timeliness of regulatory recovery cited as a contributing factor—which may lead to a credit rating downgrade and higher cost to borrow.[45]

Q. How does PGE's overall financial health impact customers?

A. Excessive under-recovery that fails to reflect the cost-of-service on an ongoing basis will hinder our ability to secure low-cost capital, thereby increasing the overall cost of capital and placing upward pressure on future rates for customers. Furthermore, without the capacity to attract capital investments, the utility would be constrained in its ability to invest in system safety and reliability enhancements. Lack of investment would also impede a timely transition to renewable energy sources and adoption of necessary new technologies. These investments ultimately benefit customers through increased access to clean energy options, improved environmental sustainability, and a more resilient and technologically advanced grid infrastructure.

C. Rate Effective Date

Q. Please describe CUB's position regarding the rate effective date of rate reviews.

A. CUB provides an analysis of the challenges faced by customers within our service area during the month of January, highlighting the reasons why this period is not well-suited for utility price increases. Among the various factors discussed, they emphasize that January typically experiences peak energy consumption due to low temperatures, necessitating increased usage of heating systems. As a result, they assert that PGE should have aligned the 2025 test year filing with the in-service date of the Seaside project, and they propose an approach that would effectively shift the timing of the price change to align with CUB's preferred timeline.

[45] Moody's Credit Opinion, Portland General Electric Company, June 25, 2024

Staff echoes this assertion in their opening testimony, although they do not put forth a specific proposal to modify the effective date.

Q. What is PGE's general response to this issue?

A. We have thoughtfully evaluated CUB's testimony highlighting the difficulties associated with price changes during this time of year. It is important to note that shifting this timeline is not simple for PGE, which is the reason we are maintaining our January 1, 2025, for this case. Our operations are structured around a calendar year financial planning model, which makes it challenging to suddenly dissociate rate changes from our budgeting, accounting, and planning processes.

That said, we recognize the potential impact on our customers, and we are investigating alternate pathways that could allow for a transition to a different rate review timeline in the future. However, implementing an immediate transition to a different timeline presents significant operational challenges given our current systems and processes. Our goal is to find solutions that align with our financial and operational requirements while also addressing the needs and well-being of our customers.

Q. You say PGE is investigating ways to move away from January 1 effective dates for general rate cases. What other considerations are there for such a change?

A. PGE is open to shifting the rate effective date of future cases. However, PGE notes that such a shift would (a) compound the scale of the rate increase by accounting for additional months of capital additions; and (b) add complexity to Parties' GRC engagement process, as PGE's systems are designed around a calendar year.

Q. Although you have shown consideration for CUB's position on the timing of rate cases going forward, is it appropriate for CUB or Staff to suggest that PGE acted improperly by filing a rate case with a proposed January effective date?

A. We are open to making changes in the future, but we respectfully disagree with the suggestion that PGE acted improperly by maintaining consistency in filing this case with a January effective date. Instead, we would contend that the expectation for us to deviate from a January rate effective date represents a departure from established norms.

Q. Please provide evidence to substantiate your position that aligning a PGE general rate review with a mid-year effective date is actually the uncommon request.

A. Based on our review of the last thirty years, PGE has not filed a single rate review that was not based on a calendar year. Further, the only rate review PGE is aware of that did not have a January 1 effective date was Docket No. UE 394, which PGE intentionally delayed due to the worldwide COVID pandemic.

Q. Please list the years that PGE has filed general rate cases in the 21st century.

A. Table 2 below is shows all of PGE general rate case files since 2000.

Table 2
PGE Filed Rate Cases 2000-2024

Docket	Filing Date	Test Period	Rate Effective Date
UE 115	Oct 2, 2000	Jan 1, 2002 – Dec 31, 2002	Jan 1, 2002
UE 180	Mar 6, 2006	Jan 1, 2007 – Dec 31, 2007	Jan 1, 2007
UE 197	Feb 27, 2008	Jan 1, 2009 – Dec 31, 2009	Jan 1, 2009
UE 215	Feb 16, 2010	Jan 1, 2011 – Dec 31, 2011	Jan 1, 2011
UE 262	Feb 15, 2013	Jan 1, 2014 – Dec 31, 2014	Jan 1, 2014
UE 283	Feb 13, 2014	Jan 1, 2015 – Dec 31, 2015	Jan 1, 2015
UE 294	Feb 12, 2015	Jan 1, 2016 – Dec 31, 2016	Jan 1, 2016
UE 319	Feb 17, 2017	Jan 1, 2018 – Dec 31, 2018	Jan 1, 2018
UE 335	Feb 15, 2018	Jan 1, 2019 – Dec 31, 2019	Jan 1, 2019
UE 394	July 9, 2021	Jan 1, 2022 – Dec 31, 2022	May 9, 2022
UE 416	Feb 15, 2023	Jan 1, 2024 – Dec 31, 2024	Jan 1, 2024

Q. What specifically does CUB propose regarding the rate effective date in this case?

A. CUB proposes the Commission establish a base rate tracker to delay PGE's filed rate effective date from January 1, 2025 to the date that the Seaside BESS project comes into service, which is estimated to be mid-year.

Q. Does CUB's proposal align with the intended purpose and design of a tracker?

A. No, while we understand the intention behind CUB's proposal, we must disagree that their proposal is actually a tracker. A tracker is a mechanism that facilitates the timely inclusion or exclusion of certain expenses or revenues in customer rates. The purpose of a tracker is to ensure that the benefits customers experience are appropriately aligned with the prices they pay. However, CUB's proposed mechanism appears to be designed to intentionally create a mismatch between these two factors by artificially reducing base rates at the conclusion of a rate case.

While we are not legal experts, this mechanism seems to be an attempt to circumvent the law, which allows the Commission to suspend the implementation of new rates for a maximum period of ten months from the date of the tariff filing. CUB's suggestion that a Commission could approve rate levels that do not take effect for an additional six months following such a deadline would functionally void the statutory timeframe.

Q. CUB states that it "rejects the idea that the Commission can schedule a rate increase several months after the end of the suspension period when a utility asks for it but cannot do so when a customer group asks."[46] Please explain the error within this statement.

A. The rate increase "several months after the end of the suspension period" is to align customer prices with the benefits being received by customers. CUB's request seeks the opposite.

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[46] CUB/100, Jenks/68.

Q. Is CUB's request reasonable?

A. Based on the information that CUB has highlighted within their testimony, we agree it is reasonable for us to work together to find a different way to file rate cases in the future. However, we do not find it reasonable in this case for CUB to attempt to force a different rate effective date. CUB's approach to delay the rate effective date raises important legal concerns that will be addressed in briefing. In addition, such an approach would undermine PGE's effort to introduce rate increases steadily through two-steps by using a tracker for the Seaside project.

Moreover, despite objecting to PGE's request for a new regulatory mechanism, here CUB is proposing a novel—and likely illegal—new regulatory approach. The concept of deferring PGE's entire revenue requirement increase (which triples the size of the Seaside investment) pushes the Commission away from the traditional cost-of-service paradigm. We find CUB's continued rejection of the cost-of-service regulatory model to be concerning.

Q. What does PGE request of the Commission regarding CUB's proposal?

A. We request that the Commission adhere to the rate effective date for this case as requested by PGE and reject CUB's proposal.

IV. Qualifications

Q. Josh Kliever, please state your educational background and experience.

A. I received Bachelor of Science Degrees in Finance from Oregon State University, and a Post Bachelor Certification in Accounting from Linfield College. I have more than 15 years of experience in the utility industry. I have also completed various executive leadership development programs, including the Willamette University Utility Management Certification Program. My employment with PGE started in November 2005 and I have over 10 years of leadership experience for financial forecasting, budgeting, reporting, capital planning and financial modeling. Prior to PGE, I worked in finance at Tektronix Inc.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Affordability Programs and Proposals

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Kristen Sheeran
Jake Wise

August 14, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Kristen Sheeran. I am the Senior Director of Policy Planning and Sustainability at PGE. My witness qualifications appear at the end of this testimony.

My name is Jake Wise. I am the Manager of Strategy and Planning for Energy Savings and Affordability at PGE. My witness qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our reply testimony responds to the opening testimony of the Staff of the Public Utility Commission of Oregon (Staff), the Oregon Citizens' Utility Board (CUB), and Verde (jointly, the Coalition) regarding actions taken to advance energy justice and promote the affordability of PGE's services to its customers, especially in the context of PGE's Income-Qualified Bill Discount (IQBD) program. We also respond to the Alliance of Western Energy Consumers (AWEC) testimony concerning enrollment and cost allocation for IQBD.

We discuss how PGE works to keep costs low while providing safe and reliable service. Finally, we address CUB and Staff's arguments that affordability concerns should be resolved through caps on what PGE can recover in rates. We explain how their rate cap proposals are inconsistent with the Commission's charge to set just and reasonable rates, are not a balanced approach, and impede PGE's ability to provide service to our customers, which will create more harm for all customers.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have six sections:

- Section II – Overview & Summary
- Section III – Comprehensive Approach to Affordability
- Section IV – Procedural Equity and Stakeholder Input
- Section V – Communications and Bill Transparency
- Section VI – Rate Caps
- Section VII – Qualifications

II. Overview and Summary

Q. Please provide a summary of how PGE considered customer impacts before seeking this rate review and the role affordability played.

A. PGE must undertake essential initiatives for the safety, reliability, and resilience of our electric grid. Understanding the critical importance of these efforts, we recognized that delaying essential projects would undermine the long-term sustainability of our infrastructure and the quality of service provided to our customers. To support these efforts, we began the intensive ten-month process of a rate review proceeding before the Commission.

PGE's ongoing efforts to modernize and fortify our generation, transmission and distribution infrastructure are crucial for several reasons. Firstly, aging power lines and poles pose reliability risks, leading to unexpected outages and disruption to our customers' lives. By systematically replacing them, we provide a more dependable power supply for our customers' homes, businesses, and community.

Secondly, substations and transformers play a pivotal role in electricity distribution. They are integral to electricity distribution. Upgrading them enhances their durability and performance, reducing maintenance costs and minimizing downtime. This means fewer interruptions for our customers.

Thirdly, cutting-edge grid automation and monitoring technologies optimize operations. Real-time data allows PGE to respond swiftly to issues, prevent cascading failures, and maintain grid stability. These investments are essential for adapting to the evolving energy landscape and accommodating renewable energy sources.

Lastly, the installation of utility-scale battery energy storage systems serves dual purposes. Not only do they support renewable energy integration, but they also provide vital backup capacity during peak demand or emergencies. This resilience allows for uninterrupted power supply, safeguarding homes, businesses, and critical infrastructure.

In summary, the cost of these infrastructure improvements is an investment in reliability, efficiency, and resilience, benefiting PGE's customers and the community. As a regulated utility, we recognize that timely cost recovery through rate increases are necessary to support these crucial activities, and PGE is diligently working to minimize and smooth the effects of necessary new investments wherever feasible, while improving and expanding access to programs that help customers manage their energy usage and impact of energy costs for customers.

PGE Exhibits 1100, 1600, and 1700 discuss in more detail PGE's approach to capital planning and the efforts we are undertaking to improve the generation and delivery of energy for customers. Our testimony herein further addresses the many ways PGE engages stakeholders from the energy justice communities and works to address energy burden for our most vulnerable customers through PGE programs and collaborative efforts to help customers manage energy usage, reduce bills, and provide bill assistance.

Q. Please summarize the Coalition's positions to address affordability for low-income or other vulnerable customer groups and overall.

A. Staff argues that the principles of energy justice entail the use of an energy equity framework, of which a key element is distributional equity.[1] Staff also highlights comments provided at a public comment hearing in this rate review to underscore that customer energy burdens and economic hardships are not limited to customers falling into specific income tiers.[2] CUB argues

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[1] Staff/200, Scala/4.
[2] Staff/1900, Ayres/16.

that PGE should conduct an equity impact analysis on how rate increases impact vulnerable customer segments within the service area.[3] Verde testifies that "unaffordable rates disproportionally impact low-income households."[4] The Coalition offers several recommendations aimed at affordability for low-income households and CUB proposes a rate cap policy that would apply to all customers.

Q. How does PGE respond to these arguments?

A. PGE prioritizes actions that enable accessible and affordable service to low-income and vulnerable customers. PGE welcomes feedback for improvement, which we respond to in more detail below. Some efforts we are taking today include advancing an encompassing affordability approach that improves upon coordination between existing program offerings and incorporates feedback. PGE has also recently completed an Energy Burden Assessment (EBA) performed by Empower Dataworks.[5] The EBA provides data-driven insights and feedback to further our important work in this area on behalf of our customers.

Q. Please identify other testimony or items that are addressed in your testimony.

A. AWEC recommends a change from the self-attestation approach for Income Qualified Bill Discount (IQBD) enrollment towards a requirement for income verification for participants during enrollment. We will discuss later in our testimony how this approach could result in higher costs for the program. AWEC also proposes a modification to the non-residential per customer cost-cap design under Schedule 118, the tariff that recovers the costs for the IQBD

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[3] CUB/300, Wochele-Jenks/2.
[4] Verde/100, Segovia Rodriguez/3.
[5] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 416, Energy Burden Assessment (Jun 28, 2024), also filed *In the Matter of Public Utility Commission of Oregon Implementation of House Bill 2475*, Docket UM 2211 (Jul 3, 2024).

program across customer classes. We explain further in our testimony some of the administrative challenges of AWEC's proposal and the potential for significant cost shifting.

We also respond to major points from public comments. In relation to CUB and Staff's proposed rate caps to deny cost recovery for prudently incurred expenses (as opposed to rate class structuring), we discuss how such proposals deviate from the fundamental cost-of-service framework.

III. Comprehensive Approach to Affordability

Q. How does PGE try to help keep costs low for all residential customers?

A. PGE takes a comprehensive approach to affordability that includes, but is not limited to: procuring resources at least cost/least risk through competitive bidding processes, simplifying processes to enhance operational efficiencies and manage costs, leveraging federal, state, and local funding sources to lower the costs of the clean energy transition, expanding customer access to energy efficiency, and launching new programs to help customers manage and reduce energy usage and mitigate costs such as Smart Thermostat, Time of Day, Peak Time Rebates and Equal Pay.

Q. Please explain PGE's vision for a comprehensive approach to affordability for more income vulnerable customers.

A. PGE offers support for our lowest-income customers through three pillars: bill discounts, bill assistance, and bill reduction. Bill discounts occur through the design and operation of the IQBD program. Bill assistance is comprised of funds that are directly available to eligible customers via utility and publicly funded programs including Oregon Energy Assistance Program (OEAP) and Low Income Home Energy Assistance Program (LIHEAP) administered through partnerships with Community Action Partner (CAP) agencies. Bill reduction comprises all efforts to help customers manage their energy use, notably enhanced energy efficiency and weatherization programs for low-income households. These three pillars are supported by outreach, customer service, and program administration and design to meet customer needs.

Q. How is PGE evolving its programs around affordability?

A. PGE continues to evaluate, identify, and prioritize reforms to improve program effectiveness. The results of the EBA were shared with community partners this summer and filed with the

Commission in June.[6] In the near term, PGE intends to discuss changes to offerings based on the EBA findings at the August meeting of PGE's Community Benefits and Impacts Advisory Group (CBIAG) and then submit changes to the discount program in September.[7] We discuss in the following sections of testimony the recommendations from the Coalition, in particular those we are analyzing, and that align with the EBA findings.

Q. Please summarize the major findings of the EBA.

A. The EBA concluded that PGE's "IQBD program is operating effectively and is following energy assistance program best practices"[8], Empower Dataworks, the consultancy who conducted the EBA, found no major recommended changes needed to the foundation of PGE's IQBD program.

The majority of the EBA recommendations are what Empower Dataworks describes as auxiliary components that can be added to PGE's energy affordability approach, such as keeping up the momentum for IQBD program enrollment as the program matures or leveraging energy efficiency for sustained energy burden reduction. Empower Dataworks points out that at program maturity (year 5+) the best practice is for a utility-offered bill discount program to target 60-70% of the dollar needs for low-income high-energy burdened households[9] (of which there are approximately 118,000 within PGE's service territory). With the additional projected participation, Empower Dataworks indicates PGE's IQBD program should hit this 60-70% utility-offered bill discount target of energy burden needs in 2025.

[6] UE 416, Energy Burden Assessment (Jun 28, 2024).
[7] UE 416, Order No. 23-386 (Oct 30, 2023) from the Sixth Partial Stipulation, Section 13 "b. Parties agree that PGE will complete a LINA study by June 30, 2024. c. Parties agree that PGE will submit a new discount program informed by the LINA report within 90 days of receiving the report." Note that LINA is Low-Income Needs Assessment which is now referred to as the Energy Burden Assessment.
[8] UE 416, Energy Burden Assessment at 28 (Jun 28, 2024).
[9] *Id*. at 30.

Q. Staff recommends PGE extrapolate energy burden findings to reflect impacts of the January 1, 2025 rate increase under consideration in this case.[10] Has PGE completed this analysis?

A. Yes. An analysis based on the high-level assumptions and based on the initially filed January 1, 2025 price increase shows an increase in total assistance need of about $12 million per year. PGE cautions this projection relies on a forecast of economic conditions and assumptions on the final Commission-approved tariffs and should not be relied upon as a final amount. Consistent with the EBA methodology, this estimated amount, not yet finalized, is indicative of the need for all low-income high-energy burdened customers to be met with the combination of IQBD, public assistance, and weatherization.

A. Bill Discount Program (IQBD)

Q. Please provide a summary of PGE's IQBD program.

A. PGE was the first Oregon utility to implement an IQBD program. PGE's IQBD program was initially approved by the Commission in April 2022, and discounts were expanded in January 2024. IQBD has five income-based tiers of percentage discounts that apply to customers with gross household income at or below 60% of the Oregon State Median Income (SMI),[11] with the highest monthly bill discount of 60% provided to those with 0-5% of SMI.[12]

While a relatively new program, the IQBD outreach efforts of both PGE and community partners like Oregon's CAP agencies, the Energy Trust of Oregon (ETO), and PGE's CBIAG, have spread word to many qualified PGE residential customers. IQBD continues to grow so that as of July 2024, approximately 85,000 residential households were enrolled in the IQBD

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[10] Staff/200, Scala/33.
[11] Household income, as a percentage of SMI, is adjusted for household size.
[12] The 60% discount level was effective January 2024 and was approved as part of the stipulation in UE 416, Order No. 23-386 (Oct 30, 2023).

program. PGE anticipates approximately 100,000 qualifying customers will be enrolled in IQBD by the end of 2024.

Q. Did the Coalition make recommendations regarding IQBD?

A. The Coalition provided several recommendations regarding IQBD which spanned from outreach and enrollment practices, enrollment expansion to master-meter buildings, tier levels and tier design, eligibility conditions, eligibility verification, and cost recovery.

Q. What does the Coalition recommend for IQBD enrollment expansion?

A. Staff encourages coordination with CAP agencies, other Community-Based Organizations (CBOs), and the CBIAG to consider the timing of messaging,[13] outreach alignment with Community Solar and other programs, and improvements to achieve "low barrier and timely enrollment."[14]

Q. Is PGE working to enhance IQBD enrollment outreach?

A. Yes. PGE is already working on ways to enhance IQBD enrollment outreach. Staff's enrollment recommendations align well with PGE's efforts. Specifically, PGE is increasing engagement with CAP agencies and soliciting input from the CBIAG. PGE's enrollment outreach reforms strive for increased awareness and participation from highly impacted customer groups, including high-energy burden customers, high-energy consumers, and mobile home occupants.

Q. What is Staff's recommendation regarding expansion of IQBD enrollment to master metered buildings?

A. Staff observes a potential gap in IQBD serving residential customers living in master metered buildings.[15] Staff encourages PGE to coordinate with the Oregon Housing and Community

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[13] Staff/1900, Ayres/18.
[14] *Id*. 20-23.
[15] *Id*. 18-19.

Services Agency (OHCS) to design and implement a program to serve buildings determined to have a certain percentage of low-income occupants, like the program offered by Pacific Power.[16]

Q. Does PGE support Staff's proposal regarding master-metered buildings?

A. PGE sees IQBD program expansion to master-metered buildings as a recommendation that should be analyzed and considered as part of the holistic approach for the EBA recommendations. There are several data and billing complexities of implementing and operating IQBD for master-metered buildings that would need to be addressed.

Q. Please summarize the Coalition's recommendations on the IQBD discount levels.

A. Verde recommends increasing the discount level for customers earning less than 30% of SMI.[17] Other parties do not make specific recommendations on IQBD discount tier levels; however, both Staff and CUB recommend further analysis of discount tiers and that the new discount tiers should be effective January 1, 2025, to align with the target rate effective date of the general rate case.[18]

Q. Are the Coalition's recommendations on IQBD discount tiers consistent with the recommendations in the EBA?

A. The EBA found that "current discount rates are suitable" for customers in the 31-45% SMI (20% discount) and 46-60% SMI (15% discount) tiers. While the EBA did not recommend a higher discount for the lowest income tier, the EBA did recommend that PGE continue to assess the feasibility and benefit of enhanced discounts for lower-income tiers versus the costs.[19]

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[16] Pacific Power offers a 30% discount for certain master meter buildings. Schedule 7 of Pacific Power Oregon tariff, issued October 3, 2022.

[17] Verde/100, Segovia Rodriguez/10.

[18] Staff/1900, Ayres 17.

[19] UE 416, Energy Burden Assessment at 31 (Jun 28, 2024), see also PGE EBA slide 12 of the CBIAG presentation. PGE_EBA 2024 Findings Deck v2.pptx (ctfassets.net)

Q. What is the current and forecasted cost for IQBD?

A. The IQBD program cost in 2024 is an estimated $45 million, growing to $54 million in 2025 based on projected enrollment levels and current program design. For a residential customer, the cost of the IQBD program currently equates to $1.88 per month. Residential customers also pay $0.60 per month for Schedule 115 Low Income Assistance, and $2.21 per month on average for the Public Purpose Charge, which includes support for low-income housing and weatherization. These three charges total $4.69 per month.

Q. What is the IQBD estimated program cost with increased discount levels for the 0-30% SMI tier?

A. PGE's preliminary analysis, as recommended in the EBA, estimates that increasing discount levels for customers earning less than 30% SMI would increase the 2025 program cost by approximately $23 million, for a total program cost of approximately $77 million.[20] At discount levels proposed by Verde,[21] the 2025 program costs would nearly double, from $54 million to just over $100 million.[22]

Q. How does PGE intend to proceed with recommendations for updates to its IQBD program?

A. PGE is evaluating the cost versus benefits of modifications to the existing IQBD tiers, and any changes to the discount levels or other program modifications would be considered within the EBA process and PGE's September filing.

[20] Based on increases to 90%, 65% and 45% for the top three tiers.
[21] Verde/100, Segovia Rodriguez/9.
[22] These cost projects account for impacts from PGE's request in this docket for 2025.

Q. Please summarize recommendations on enrollment verification.

A. Verde recommends eliminating the post-enrollment process[23] citing customer friction from providing paperwork in the process and erosion of trust.[24] AWEC recommends PGE add a requirement for independent verification of income level at the time of enrollment in the program.[25] Staff takes a middle position, preferring the current post-enrollment verification level of 3% not be increased.[26]

Q. What were the EBA findings regarding enrollment verification?

A. The EBA recommends further consultation and design with the CBIAG to find ways to perform more targeted verifications, as opposed to the current randomized process, to increase the effectiveness of enrollment verification.[27]

Q. What does PGE propose regarding enrollment verification?

A. PGE supports exploring a more targeted approach for future IQBD post-enrollment verification, as recommended in the EBA, with input from the CBIAG. We understand AWEC's concern for the potential that ineligible customers may enroll in IQBD if verification does not occur at the time of enrollment. However, PGE previously evaluated this option and determined that not only would pre-enrollment verification present a barrier to enrollment for eligible customers, the costs to verify income eligibility would exceed the avoided cost of having a limited number of ineligible customers enrolling when the self-certification approach is paired with the possibility of post-enrollment verification. We were also mindful that a significant portion of

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[23] Verde/100, Segovia, Rodrigues/17.
[24] Verde/100, Segovia Rodriguez/17.
[25] AWEC/200, Kaufman/33 to 34.
[26] Staff/1900, Ayres/27.
[27] UE 416, Energy Burden Assessment at 37 (Jun 28, 2024).

IQBD participants would be automatically enrolled due to their verified eligibility to receive assistance through OHCS-administered bill assistance programs.

Q. What are AWEC's proposed changes to IQBD Cost Recovery (Schedule 118)?

A. AWEC has two recommendations for the IQBD cost recovery in Schedule 118.[28] First, AWEC proposes that the per-customer cap on cost recovery be based on a new approach to bill aggregation, where a cap would apply to all usage or revenue under "a common parent entity" instead of a kWh cap per service agreement or in some cases, per Site.[29] To avoid confusion, PGE will refer to AWEC's definition of a customer as a "Common Parent Entity" since a customer is typically used to indicate service agreements or service points within PGE rate design. AWEC's second recommendation is to allocate costs to base service schedules using total class revenue instead of load.[30]

Q. Why does Schedule 118 include a per-site cap on collections?

A. Schedule 118 design was based on Schedule 115, low-income bill payment assistance cost collection.[31] Schedules 115 and 118 include a cap on kWh subject to the respective charge. In cases where multiple service points are part of a designated site, the cap is assessed on the aggregate site kWh, not for each service point.

Q. What does Staff recommend regarding IQBD Cost Recovery (Schedule 118)?

A. Staff signals interest in removing the non-residential cap and changing cost recovery collection to a percent of the bill (revenue) but stops short of making firm recommendations.[32]

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[28] AWEC/200 Kaufman/32.
[29] A Site is defined as co-located buildings or facilities owned by a single retail Customer. See PGE Tariff, Rule B.
[30] AWEC/200 Kaufman/33.
[31] ORS 757.612.
[32] Staff/1900, Ayers/44-45.

Q. How does PGE respond to AWEC's and Staff's proposed changes to Schedule 118?

A. PGE does not support AWEC's proposal to change the definition of customer based on bill aggregation because it would require considerable time, effort, and cost to implement and maintain the data necessary to apply AWEC's definition. A cost-recovery cap in Schedule 118 based on Common Parent Entities is a completely new way to calculate and bill customers. PGE does not collect from customers sufficient information to definitively identify Common Parent Entities and map them to individual service agreements and it would also require ongoing maintenance of the relationships between service agreements and Common Parent Entities as this is not a natural aggregation of service points for both PGE and customers.[33]

Q. How does PGE respond to the recommendation to change Schedule 118 to a revenue-based allocation?

A. Moving to a revenue-based allocation, as proposed by AWEC, could substantially reduce the amount paid by large commercial and industrial customers on Direct Access service, which may be contrary to the intention of ORS 757.695(2).[34] It would also reduce collections from large commercial and industrial customers on Cost of Service because these schedules tend to have a lower all-in price per kWh. All other customer classes would see increases to their relative contributions.

Staff recommends that PGE assess a more explicit percentage of bill structure, where residential customers would pay differing amounts based on average usage instead of the current flat charge. This cost recovery structure would shift collections to high-usage customers and

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[33] An attribute in the billing system would be required to implement AWEC's proposal. PGE does not currently need this information in account set up for billing.

[34] ORS 757.695(2) requires that "consumers that purchase electricity from electricity service suppliers pay the same amount to address the mitigation of energy burdens as retail electricity consumers that are not served by electricity service suppliers."

away from low-usage customers, which also means customers with solar generation (low usage) would contribute less to IQBD.

PGE has provided an IQBD work paper with formulas intact so that Staff, AWEC and others can evaluate the impact of alternative caps and cost recovery allocations on customer segments.

Q. How does PGE respond to other IQBD design, scope, outreach, and verification recommendations?

A. PGE seeks continuous improvement to our programs and offerings both for customer experience and effectiveness. PGE's filing in September will incorporate learnings from the EBA and is the appropriate proceeding for PGE to put forward a proposal that will also be informed by the Coalition's recommendations in opening testimony in this docket.

Q. What is PGE's response to more foundational design proposals?

A. As noted above, the EBA found that PGE's IQBD was operating effectively and in alignment with energy assistance program best practices. The EBA recommendations should be the focus of near-term design discussions as the program matures and more information on the program's performance and impacts is known.

B. Bill Assistance

Q. What bill assistance programs are available to help lessen the energy burden for residential customers?

A. Eligible customers can seek bill assistance from LIHEAP and other programs through community action partners. PGE works with CAP agencies to help customers in arrears find applicable bill assistance, including elements of the LIHEAP and OEAP programs. Customers who are having trouble paying their bills are encouraged to seek help through these programs and PGE will typically help them get referred to and connected with these programs. PGE is also implementing a new voluntary offering that will provide additional bill assistance funding to the Oregon Energy Fund through a program targeted for launch by the end of 2024 called Bill Round-Up.

Q. What other support does PGE offer to customers who have difficulty paying their bills and who have a past-due balance?

A. PGE offers many options to residential customers having difficulties paying a bill or who have past-due balances. These include: (1) residential customers bill budgeting options through Equal Pay; (2) energy assistance referrals; (3) payment extensions through Time Payment Arrangements (TPAs) to divide outstanding balances over 12 months; and (4) the waiver of late fees for IQBD program participants.

Q. Please summarize the Coalition's recommendations for additional methods for bill assistance, specifically bill assistance aimed at past-due balances (arrearages).

A. Staff, CUB, and Verde present various recommendations for arrearage management and forgiveness targeted to customers in the lowest IQBD income tiers. CUB requests a comprehensive arrearage management and arrearage forgiveness program informed by stakeholder engagement and including both arrearage forgiveness for customers falling into the lowest IQBD income tiers and consideration of energy-burdened customer needs.[35] Staff recommends that PGE make a proposal for a targeted arrearage management plan.[36] Staff also recommends additional analysis and engagement to inform a more comprehensive arrearage plan within the IQBD update. Staff recommends interim policies to cap growing arrearage balances, presumably with a form of forgiveness pending the resolution of an

[35] CUB/300, Wochele-Jenks/31.
[36] Staff/1900, Scala/33.

arrearage management plan.[37] Verde recommends an arrearage forgiveness program for the 0-46% SMI range of IQBD program enrollees.[38]

Q. Does the EBA recommend an arrearage forgiveness program as a form of bill assistance?

A. Yes, but at a high level, and specific to customers enrolling in IQBD where forgiveness of arrears is a retroactive application of the bill discount percent and only up to a set amount.[39] The EBA makes a medium-priority recommendation to "assess the feasibility and benefit vs. cost of a capped budget arrearage relief program."[40] The EBA notes the challenge in designing arrearage relief programs because "some customers do not address arrearages until an actual disconnection happens."[41] An expansive arrearage forgiveness program could inadvertently forgive charges owed by customers with the ability to pay, at the expense of all other customers.

Q. Does PGE see value in an arrearage management program?

A. PGE views an arrearage management program as a new offering with design details and cost considerations best addressed in the EBA process or in other comprehensive affordability dockets, such as Docket No. UM 2211 (UM 2211).

Q. What will the cost of an arrearage management program be to non-participants?

A. The cost of an arrearage management program will depend on specific program design details. The EBA estimates that a program that provides limited arrearage relief to IQBD customers could help approximately 3,000 to 4,000 customers with a program cost of $1.0 million.

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[37] Staff/200, Scala/31.
[38] Verde/100, Segovia Rodriguez/16.
[39] UE 416, Energy Burden Assessment at 32 (Jun 28, 2024).
[40] *Ibid.*
[41] *Ibid.*

C. Bill Reduction

Q. Please summarize the Coalition's recommendations regarding energy efficiency and weatherization actions.

A. Staff recommends that PGE increase efforts to connect high-energy usage customers with weatherization services[42] and increase data sharing with the Energy Trust of Oregon (ETO) to increase program effectiveness.[43] CUB advocates for a holistic approach to address arrears and affordability challenges, inclusive of energy efficiency, weatherization and distributed energy resources (DERs).[44] CUB recognizes PGE's ongoing work with ETO to help improve home energy performance and mitigate the impacts of high energy usage by supporting weatherization and energy efficiency retrofits.[45] Verde describes the need for increased assistance for IQBD households to identify and address energy efficiency and weatherization opportunities.[46]

Q. Does PGE agree with the objective of increased energy efficiency?

A. Yes. PGE views energy efficiency as an important resource for meeting decarbonization goals and a resource that provides additional benefits for customers, such as lower bills through lower energy use and comfort.[47] Energy efficiency deployment can currently leverage Federal funds to benefit our customers.

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[42] Staff/1900, Ayres/24-25.
[43] Staff/1900, Ayres 40.
[44] CUB/300, Wochele-Jenks/20.
[45] CUB/100, Jenks/7 (quoting CUB/103).
[46] Verde/100, Segovia Rodriguez/28.
[47] PGE/100, Pope–Sims/23.

Q. How does PGE monitor high-energy usage customers and make referrals to enable weatherization?

A. Annually, PGE identifies residential customers who received energy assistance in the preceding 12 months and had an average monthly usage of 2,000 kWh or more and then refers these customers to CAP agencies for weatherization outreach.

Q. What other ways does PGE help customers manage energy usage and anticipate bill amounts?

A. PGE offers customers weekly energy alerts that notify them of their weekly usage and provide projected monthly bill amounts. By the end of this year, PGE will launch website updates that will give customers a single view of their current billing period usage and a projected monthly payment based on their usage to date. On the same website, customers can view and sign up for energy-savings programs and see the programs they are already enrolled in.

Q. How is PGE collaborating with ETO to increase the effectiveness of program delivery?

A. PGE and the ETO propose moving from a two-year planning cycle to a multi-year (2026-2030) time horizon, and from an activity-based plan to an outcomes-based, co-deployment framework. These two planning changes will allow PGE and ETO to maximize value for customers, accelerate procurement of energy efficiency as determined in PGE's Integrated Resource Plan (IRP) in compliance with Oregon House Bill 2021 (HB 2021), and align efforts based on organizational and program readiness.

Q. Please explain what "co-deployment" is and what it could look like for PGE and ETO.

A. Co-deployment is using a shared strategy, with common marketing, outreach, and messaging, to efficiently deliver complementary energy services to shared customers. Through co-deployment customers benefit from behind-the-scenes coordination to streamline participation and total delivery cost reduction for all customers. This effort is aligned with the implementation of Oregon House Bill 2475 (HB 2475)[48] through UM 2211, which has a goal of reducing energy burden and increasing the ability for customers to benefit from additional availability of public sector funding. While PGE will work with ETO through co-deployment to better target programs to support customers, we are always mindful of the need to respect customer expectations for the privacy of their information; more so with protections for customer data afforded through the Oregon Customer Privacy Act, which went into effect in July of this year.[49]

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[48] Oregon House Bill 2475, passed in 2021, also known as the Energy Affordability Act.
[49] Oregon Senate Bill 619, passed in 2023, also known as the Oregon Consumer Privacy Act.

IV. Procedural Equity and Stakeholder Input

Q. Please describe procedural equity and the items addressed with a procedural equity lens in this section.

A. Procedural equity in the context of energy justice refers to the fairness and transparency in decision-making related to energy policies and impacts, and access to the process. It emphasizes the involvement of affected communities and allowing their voices to be heard while working to have a more just and inclusive process. In this section we address topics in the Coalition's opening testimony addressing the accessibility of affordability-related and rate case venues.

A. Procedural Equity in Affordability Actions

Q. Please summarize PGE's approach to procedural equity in scoping and design of affordability measures.

A. PGE proactively gathered input in the design of its initial IQBD program and convened a group of stakeholders that were involved in the development of HB 2475 throughout 2022 and early 2023 to advise on our initial IQBD program offering. Since then, we have continued to provide program updates to that group including a meeting to inform our efforts to have an EBA conducted by a third-party expert and then sharing the resulting EBA findings and recommendations. The CBIAG has also been instrumental in reviewing and providing feedback on EBA recommendations, and we anticipate continuing discussion on these topics in upcoming meetings, including this month's CBIAG.

Q. Does Staff recommend additional procedural equity-focused actions?

A. Yes, Staff makes several recommendations for increased engagement in the context of PGE's EBA recommendations, as well as proposals for new process and analysis particularly focused on arrearages and disconnections. First, Staff presents recommendations for engagement of consumer advocates, CBIAG and other stakeholders following EBA publication and prior to filing a formal proposal with the Commission. This effort would include new analysis, development of proposal(s) related to disconnection and arrearage issues, workshops, and development and presentation of efforts aimed at arrearage management and disconnections."[50,51]

Q. Is Staff and the Commission addressing these topics in other dockets?

A. Yes. UM 2211 is the Commission's investigation of the implementation of differential rates and programs as authorized by HB 2475. Scoping of utilities' interim bill discount programs was advanced through UM 2211, and Staff is currently conducting a Phase 2 process considering data, programs and rates opportunities. Notably, Staff notified docket participants of a new work stream to address disconnections in Phase 2, including a workshop, development of draft recommendations, and consideration of potential Division 21 rule changes and arrearage management program guidance.[52] PGE looks forward to engaging in UM 2211 on these topics and believes that is the right forum for these efforts.

Q. How does PGE respond to Staff's procedural recommendations for affordability program improvements?

A. Staff's outlined Phase 2 work streams in UM 2211 seem to address the Coalition desire for more reporting and distributional analysis alignment, arrearages and disconnections and PGE sees that as the correct venue to continue the dialogue on these topics. PGE views several of Staff's recommendations as substantially aligned with PGE's current efforts to work closely with CAP and ETO partners on outreach and coordination.

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[50] Staff/200, Scala/7, 30-31; Staff/1900, Ayres/5.
[51] Staff/200, Scala/7 at 17-22.
[52] UM 2211, HB 2475 Implementation of Differential Rates and Programs in Oregon (Aug 6, 2024).

Q. The Coalition raises the topic of arrearages and disconnections which will be addressed in Phase 2 of UM 2211. How does PGE approach customer disconnections?

A. PGE follows the disconnection process outlined in Commission-approved tariffs and rules. When a customer's payment is overdue, PGE sends a past-due notice at least 20 days before service termination and attempts to contact the customer again at least 5 business days prior to disconnection. During these interactions, PGE informs customers of their rights and options, including the opportunity to set up a Time Payment Agreement plan. Once disconnected customers contact PGE and take the necessary steps for reconnection, we can promptly restore their service, with approximately 75% of disconnected residential customers reconnected the same day or the next calendar day.[53] The disconnection process serves as a tool for PGE to manage non-payment risks and protect all customers from increased costs associated with write-offs. This approach balances the need to maintain financial stability while offering support to customers experiencing payment difficulties.

Q. Can you provide more information on arrearage and disconnection levels and trends?

A. PGE reviewed data for the past five years and does not see an increased level of residential customers with arrearages. In 2019, 10.8% of residential customers were carrying an outstanding balance for past-due amounts. In comparison, for the first five months of 2024, 9.6% of residential customers were carrying an outstanding balance for past-due amounts.

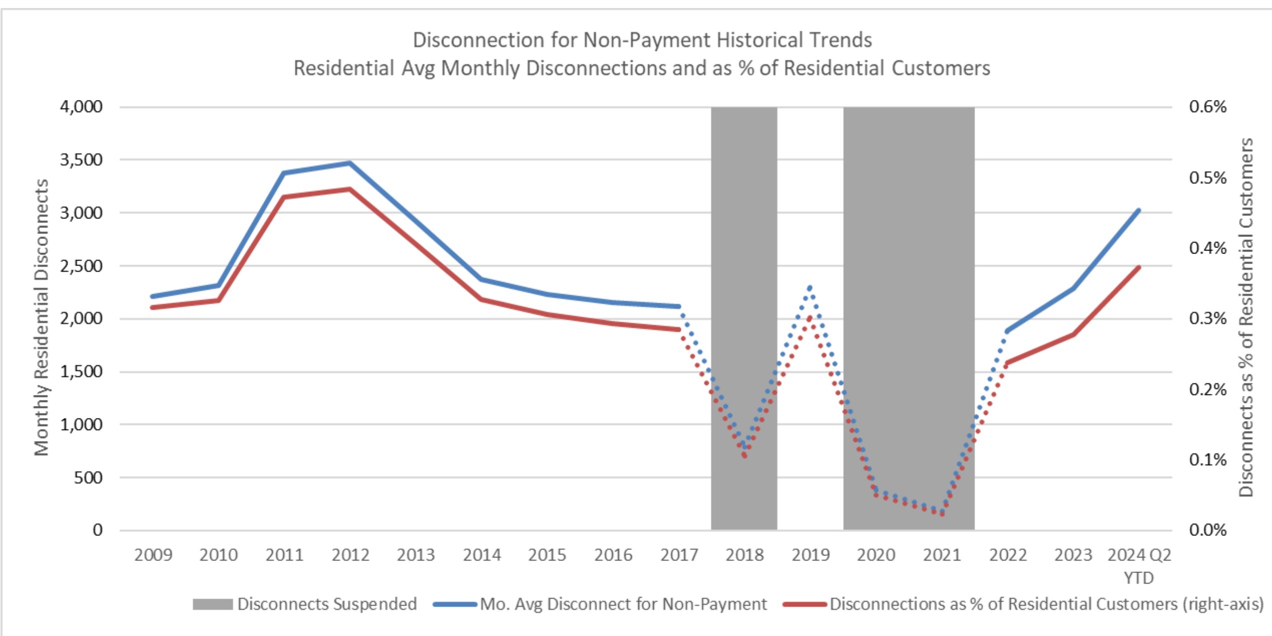
It's not clear to PGE that a trend for disconnections can be easily identified due to several interconnecting factors. Given the extraordinary COVID-19 pandemic, which led to a moratorium on disconnections, it is important to consider bill payment activity, arrearage, and

[53] Per the most recently filed RO 12 PGE 2024 Division 21 Service Disconnection Quarterly Report, for the period of February 1, 2024 to April 30, 2024, 76.35% of customers were reconnected the same or next day. See https://edocs.puc.state.or.us/efdocs/HAQ/ro12haq328677113.pdf

disconnection trends in a historical context. As a result of the suspension of residential disconnections between 2020 and 2022 due to COVID-19, we are now seeing the relative impacts of the end of the disconnection moratorium in arrearage and disconnection levels. In addition, the Division 21 disconnection rule changes approved in September of 2022[54] — which included winter weather and an AQI air quality moratorium and the extension of the disconnection notice period from 15 to 20 days among other changes—are examples of factors that can impact the month-to-month disconnection levels.

Figure 1 displays residential disconnections for non-payment over the last fifteen years expressed as both counts and as a percentage of residential customers.

Figure 1
Disconnection Historical Trends



[54] *In the Matter of Revisions to Division 21 Rules to Strengthen Customer Protections Concerning Disconnections*, Docket AR 653, Order 22-353 (Sep 29, 2022).

B. Stakeholder Input in the Rate Case Process

Q. The Commission received more than 2,300 public comments in PGE's rate case proceeding to date. Please summarize the public comments.

A. PGE has reviewed the public comments received during this proceeding. We take our customers' concerns seriously, and do not enter a rate review proceeding lightly. We have a dedicated website for the 2025 rate review where we included information on how to provide comment and input in the rate review as part of our commitment to transparency and engagement in the process.

We read the more than 2,300 comments from our customers and other stakeholders. The comments we received in this rate review and through other channels provide a sobering reminder of the struggle many Oregonians face each month to make ends meet. The comments also underscore the importance of the work we are doing for customer service and reliability, particularly our investments to build a more resilient grid. The comments we received also highlight additional opportunities where we can continue to provide transparency and information on the rate review process, and an opportunity more broadly to connect with our customers and communities.

Q. One theme in public comments was that this rate case comes too soon after the last one. How do you respond?

A. As discussed in the Overview of our testimony, PGE carefully considered the necessity of filing this rate review and ultimately, we determined a rate case filing was needed considering the capital investments we are making on behalf of our customers that were not in-service or included in the last rate case. This rate review filing is overwhelmingly a capital-based request,[55] as we held O&M request essentially flat to the prior case.

Q. Public comments expressed a desire for improved understanding regarding how the additional funds from a rate increase will be used. How do you respond?

A. The Commission's review of PGE's rate case filing is highly responsive to this concern because it allows the Commission to complete an in-depth, public review of the utility's expenses and proposals, with stakeholder input, before authorizing a further price increase. This is exactly what many of the customers commenting on this proceeding requested. PGE is committed to being transparent about its investments and expenditures related to rate increases. The rate review filing process allows for public input and scrutiny over how additional revenue from rate changes will be spent on modernizing infrastructure, increasing resilience, and meeting evolving customer needs.

The electric industry is undertaking historic changes, and the rate review is an established and proven process and will play a pivotal role in this once-in-a-generation transformation of the electric grid. It is also true that utilities are likely to file more frequent rate cases during periods necessitating system investment to align customer prices with cost structure.[56]

Q. Please respond to public comments expressing concern about the impact of PGE's practices on vulnerable populations.

A. As discussed earlier in our testimony, PGE is actively engaged with stakeholders in seeking ways to ease the burden of energy costs on vulnerable populations. Our 2024 EBA illustrates that we continue to seek a better understanding of where our system can be improved in

[55] See PGE/200, Batzler, Ferchland.
[56] Katherine Blunt, "Get Ready to Pay More for Less-Reliable Electricity," WSJ July 18, 2024, https://www.wsj.com/business/energy-oil/electricity-expensive-less-reliable-91555a33?page=1

supporting energy justice for these populations and what steps we can consider for further improvements. We welcome further dialogue with stakeholders regarding the EBA findings and how they should be applied.

Q. Customer service and service reliability was an area of concern voiced in public comments. How do you respond?

A. Many of the customers who provided public comments related to customer service and service reliability were affected by outages during the January 2024 winter storm. As extreme weather and climate change pose increasing threats to our grid and challenge reliability, we are making grid-hardening investments to our system to become more resilient in such events and deploying more technology to isolate outages. That said, we know we can continue to do better to address outage responses as impactful events of this nature provide opportunities for better communications and ongoing improvements. PGE Exhibit 1600 addresses the January 2024 storm response in more detail, including the efforts to improve the outage response and notification system.

We serve over 945,000 customers, with 830,000 residential customers, and 96,000 small businesses customers. PGE values our customers' feedback and customer satisfaction is a priority. Over the past few months, we made improvements to our systems, resources and services to continue to evolve how customers engage with us. We see it as a positive sign that our efforts to improve and enhance customer experience helped PGE secure the top national spot for utilities in the 2024 Forrester Customer Experience Survey;[57] surpassing the average U.S. Customer Index score.

[57] "Forrester's 2024 US Customer Experience Index" Forrester, Jun 17, 2024, https://www.forrester.com/press-newsroom/forrester-2024-us-customer-experience-index/

Q. Where else do you see additional opportunities based on the public comments received?

A. We have been privileged to serve Oregon communities for over 130 years. PGE serves customers only in Oregon, and most of our employees live in the communities we serve. Some public comments appear to have mistaken PGE for other utilities operating in California or elsewhere, and possibly conflated issues facing those utilities with items in PGE's rate review. (It is useful to note that there is occasional public confusion between Portland General Electric (PGE) and the unrelated California utility Pacific Gas & Electric (PG&E), and that the similarity of company name acronyms frequently results in online search results that erroneously confuse or conflate the two separate and unrelated companies.) We view this as an opportunity for PGE to continue to be an engaged and visible community leader so that our customers know us better and differentiate Portland General Electric as their local utility.

As noted above, many public comments call for a rigorous Commission review of utility filings to ensure appropriate cost controls and oversight of utility expenditures on customers' behalf. Other public comments also provided input contrary to the cost-of-service regulatory model and the protections and processes designed to prohibit unduly discrimination on different customer classes when setting prices. We again see this as an opportunity to welcome transparency and increase engagement through communications like our website and videos to provide insight into the rate review process and requirements as a regulated utility and what drives a rate review.

Q. What is PGE's response to Staff's request that PGE address how customer perspectives, specifically those from environmental justice communities was gathered and applied in the rate case?

A. PGE solicits input and engages with different customer communities in a number of venues, notably the DSP and IRP workshop series and the CBIAG. PGE collaborated extensively with stakeholder groups, including the CBIAG, as part of its engagement process to understand the key concerns related to the company's transition to cleaner energy sources. These engagements built upon the lessons learned from PGE's previous community outreach efforts. PGE's stakeholder engagement approaches have adapted and will continue to evolve to foster inclusion, accessibility, and collaboration with diverse audiences.

PGE identified that costs and potential bill increases are the primary concerns customers have with the transition to cleaner energy sources. The dependability of renewable energy sources and the potential impact of materials required for clean energy technology were also concerns raised by more than half of the surveyed participants.

In addition to these processes, PGE incorporates public input through its IRP and associated public input meetings, which address the broader system approach. PGE established the CBIAG in April 2023, which focuses specifically on equity and inclusion matters related to its clean energy transition in accordance with HB 2021.

The CBIAG brings together a diverse group of members representing environmental justice communities, community-based organizations, and community representatives, offering support services and diverse perspectives from residents within PGE's service areas. The CBIAG covers wide-ranging topics of concern, including energy burden and disconnections for residential and small commercial customers, opportunities to increase contracting with businesses owned by women, veterans or Black, Indigenous or People of Color, actions within environmental justice communities in PGE’s service area intended to improve resilience during adverse weather conditions, distribution of infrastructure or grid investments and upgrades in environmental justice communities in our service territory, including infrastructure or grid investments, social, economic, or environmental justice benefits that result from PGE’s investments, contracts or internal practices, customer experience and actions to encourage customer engagement, and other items as determined by PGE and the CBIAG. Through the CBIAG, PGE plans to continue seeking direct stakeholder feedback to build an inclusive and accessible process for consultation and collaboration.

V. Communications and Bill Transparency

A. General Rate Review Communications

Q. Please summarize feedback from customers and stakeholders about PGE's outreach prior to filing opening testimony in the 2025 GRC.

A. We heard from members of the CBIAG, community action agencies and others who represent the local communities we serve that PGE failed to share our intent to seek a rate increase in 2025. As a publicly traded company, we are subject to strict SEC restrictions on the sharing of material non-public information, including any planned rate case filings. We view the rate review itself, a 10-month process, as the forum for Staff and parties to intervene and provide careful review and feedback of our requested rate review.

Q. Staff makes a number of recommendations on future rate case process and requirements with respect to the incorporation of procedural equity before and during the rate case process. How do you respond?

A. First, we agree that more consideration and engagement with the energy justice communities during regulatory proceedings is important. Keeping in mind the time and cost commitments required to actively engage in the typical rate case process, PGE has worked and will continue to work to share information that is relevant on the issues and processes to help them navigate decisions on where and how to engage as well as issues that most impact their communities. Communicating the cost drivers of rate requests and the robust Commission process to evaluate the evidence and arguments in a rate case before issuing decisions are ways PGE continues to be proactively engaged. Specifically, PGE can continue walk-throughs with community partners, like meetings with the CBIAG after filing our rate case. We also met with Community Action Partnership of Oregon (CAPO) and Community Energy Project (CEP). At those meetings, we explained the rate case request, where to find types of information within testimony and discussed opportunities for participation such as key deadlines in the docket such as the public comment hearing, how to intervene, how to request intervenor funding and the Commission-established procedural schedule for the case.

We also realize that engagement isn't isolated to just this docket. On August 6, Staff communicated a Phase 2 Work Plan in UM 2211 and timeline that will address several topics and recommendations raised by Staff in their opening testimony. Among these are potential Standard Data Requests for rate case filing that will address the environmental justice analysis. The recommendations made by Staff in our rate case are best addressed in the upcoming UM 2211 Programs and Arrearage and Disconnection Workstreams.[58]

Q. Please summarize CUB's concerns about frequency, transparency, and communications about upcoming rate changes.

A. CUB expressed frustration that PGE provided the detailed estimated price impacts as confidential in Commission information requests and AUT updates prior to the completion of the AUT and rate case proceedings. CUB argues that keeping estimated price impacts confidential prevented CUB from sharing the information with customers so they could take action and prepare for larger bills.[59] CUB states the information on the upcoming rate increases was not provided so customers did not know bill increases would take place.

[58] UM 2211, HB 2475 Implementation of Differential Rates and Programs in Oregon (Aug 6, 2024).
[59] CUB/100, Jenks/25 at 18.

Q. How do you respond to CUB's comments that PGE should be more transparent and share information about price changes with customers before future rate changes?

A. PGE works to provide as much transparency as possible balanced with clarity to not result in confusion and inaccurate information. As a sophisticated party with more than forty years of experience participating in utility regulatory proceedings, CUB is aware that Commission regulations require PGE to provide notice of the rate case filing showing the anticipated price impacts to an average residential customer when we file a request for rate review.[60] However, there are those who are not as familiar with the rate review process and may not know all the various dockets where price adjustments are proposed, reviewed, revised, and approved, let alone how they cumulatively impact rates. If forecast amounts that are expected to change by going up or down (such as net variable power costs) are always publicly announced, customers will end up confused and frustrated as to what the actual price change amounts will be.

This is exactly what happened recently when a local news outlet stated in an article that PGE filed for a rate increase of 10.9%. This media coverage caused some customers to call PGE frustrated because they incorrectly thought PGE was seeking an additional rate increase to the amount proposed in this rate case. It is important to distinguish price change estimates within the proceeding for intervenors to review versus what is communicated to customers at the beginning of a rate proceeding and as rate changes are final.

Q. What is PGE's communication plan for price changes for customers?

A. Typically, when sharing information about price changes PGE aims to share quality information that is timely, relevant, and avoids confusion. We share information through multiple media

[60] OAR 860-022-0017.

channels and communication streams. For example, for the increases approved in the prior rate case, PGE communicated with customers through multiple channels to communicate with customers regarding the January 2024 rate increases. This included on-bill messaging, media outreach months before the increase taking effect, website updates, social media and newsletters. Communications from the time the rate case was filed to the end included information on the approximate price impacts which customers could use to budget for the upcoming year.

Q. Why did PGE mark rate change information confidential in a filing for the January 2024 price change when responding to the Commission last Fall?

A. PGE received a Bench Request from the Commission to provide this information on an ongoing basis on October 10, 2023. At that time, power costs were still preliminary and PGE had yet to calculate all of the 2024 pricing and to file with the Commission, the Advice Filings for cost recovery for supplemental schedules that were also subject to change on January 1, 2024. The information PGE had was preliminary and could be subject to change until the Commission approved each supplemental schedule. We therefore marked this information as confidential to reduce the confusion that could be caused from a preliminary, yet seemingly precise, rate change estimate which was subject to change.

Q. How do you respond to CUB's recommendation that PGE should be required to file a communications plan for rate change before additional rate changes are allowed?

A. PGE has always worked with Staff and intervenors on communications for the final rate change based on the outcome of the rate case and actively engages in media relations with major local and regional media in support of providing clear, accurate and timely information about rate reviews to our customers and the public at large. Consistency in these communications ultimately increases the effectiveness of communications and increases customer awareness and reduces confusion. PGE also provides information to the Commission's Consumer Services team, our own Customer Service Representatives, updates information on its website and has a social media campaign to increase the number of channels customers can receive information. PGE is following a similar approach this year and finds CUB's recommendation unnecessary.

B. Bill Design and Transparency

Q. CUB recommends a disallowance of 20% or approximately $8.5 million of billing-related revenue requirement related to CUB's perceived faults in PGE's bill design. How do you respond?

A. Disallowances are applied in exceptional circumstances and are intended to serve as a consequence for a specific imprudent action taken by a utility. While not attorneys, we fail to see the legal authority for the disallowance CUB is proposing and are unaware of any prior instance where the Commission has taken such punitive action, especially when information on PGE's bill is provided to comply with regulatory guidelines set by the Commission.[61] If needed, PGE will address this further in legal briefing since PGE believes that such a disallowance would be arbitrary and inappropriate for reasons discussed below.

Q. Please summarize CUB's testimony regarding PGE's bill design.

A. CUB testifies that PGE's bill is too complex, difficult to use, and unhelpful. CUB supports these claims through the example of using the bill to perform rate change calculations using a bill prior to and after the Jan 1, 2024 rate effective date to validate the average rate change provided in PGE and OPUC communications. CUB also provides screenshots of the adjustments on the residential bill to show the complexity. Comparing electricity to gas prices or food unit prices,

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[61] OAR 860-021-0120.

CUB suggests that PGE be required to show a single unit of price per kWh on the bill to improve the usefulness of the bill for customers making electrification investment decisions, such as buying an EV or Heat Pump.

Q. How do you respond to CUB's complaints about the bill design?

A. The primary purpose of a bill is to communicate to customers the amount due so customers know what they need to pay and the due date. The front page of PGE's bill—which CUB neglects to show in their testimony—is designed to show the information most important to customers:

(1) amount due;

(2) usage for the billing cycle;

(3) due date; and

(4) how their energy usage compares over the last 12 months.

Should customers want more information, the extra pages of the paper bill and the online bill presentation also contain full detail of the Schedule 7 residential main charges and an itemized listing of adjustments, taxes, and optional products and programs.

We disagree with claims by CUB that we obscure pricing information by not presenting a single value of cost per kWh.[62] Like most utilities, not all of PGE's charges are based on cents per kWh charges; this is a question of rate design. The basic charge is a flat amount per month to reflect fixed costs to serve each customer. For residential customers, most of the remaining charges are volumetric, or cents per kWh, but not all of them. Some charges, such as the Public Purpose Charge and privilege taxes, are legislatively mandated to be recovered on a percentage

[62] CUB/100, Jenks/22, at 13-15.

per bill basis. Schedules that are percentage-based, have caps, or other complexities are typically at the request of parties in settlement and approved by the Commission.[63]

PGE agrees that, where possible, the bill should be an informational tool in the utility's toolkit to help customers understand changes in usage and pricing components. While trying to meet the information needs of several hundreds of thousands of customers, we realize some may want more granular details while others may get frustrated when presented with too much data or find it not to be helpful.

PGE strives to identify updates to our processes to improve the customer experience and respond to customer feedback. While we think the current bill design balances simplicity on the first page with the required detail on later pages and online, and meets Commission regulatory requirements,[64] we are taking in CUB's suggestions to see how we can further improve the bill to make it useful and convenient for customers to read and apply to household budgeting, energy efficiency, and electrification purchases.

For example, as raised by CUB,[65] we see value in keeping all net variable power costs in Schedule 125, even in rate case years rather than rolling power costs into base rate charges. This improvement will give more transparency to the amount of the bill related to market purchases to serve customer energy needs. PGE's Exhibit 2000 describes this proposed tariff change in more detail.

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[63] As an example, in UE 416 in the Fourth Partial Stipulation, Stipulating Parties agreed to a flat usage amount of 795 kWh for Schedules 115 and 118 for purposes of calculating the charges for residential customers.
[64] OAR 860-021-0120.
[65] CUB/100, Jenks/20-21.

VI. Rate Caps

Q. How do CUB and Staff attempt to address affordability through rate cap proposals in this proceeding?

A. Both Staff and CUB propose caps on residential rate increases in this proceeding. Staff suggests that, through some combination of revenue requirement reductions and rate spread design, "the residential class" should experience "an increase or no more than three percent of revenue requirement."[66] CUB proposes that, if rates increase above 10% or 7% + CPI, then the Commission should "require application of tools to mitigate that shock"—namely, (1) deferring/phasing in rate increases; (2) setting rates at the lowest reasonable rate; and (3) requiring the utility to propose and implement other unspecified rate mitigation measures.[67]

Q. Do you have any over-arching concerns with Staff's and CUB's rate cap proposals?

A. Yes. Fundamentally, we understand that Oregon utility regulation operates under a cost-of-service paradigm. It is our understanding that ORS 756.040 requires rates to be set based on the prudently incurred costs to provide service:

> Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility, with a return to the equity holder that is: (a) Commensurate with the return on investments in other enterprises having corresponding risks; and (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.

To the extent that CUB and Staff propose *denying* cost recovery for prudently incurred costs (as opposed to structuring rate classes), we believe that such proposals are inconsistent with the fundamental cost-of-service framework.

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[66] Staff/200, Scala/38.
[67] CUB/100, Jenks/72-73, 75.

Q. How do you respond to CUB's arguments that significant price impacts for customers justifies a cap on rates?

A. We fundamentally disagree with any argument that prudently incurred costs should not be recoverable. To the extent that CUB considers caps to be an appropriate means to address price increases, we are concerned that it is inconsistent with the statutory requirements the Commission must follow to set fair and reasonable rates. CUB ignores what the Commission has previously said is the appropriate way to address "rate shock." The Commission explained that ratemaking occurs in two steps; the first being the determination of a utility's revenue requirement and the second being the allocation of that revenue requirement among customer classes in rate spread and rate design. As the Commission pointed out, "Rate shock plays no role in the first phase of ratemaking—the determination of a utility's revenue requirement."[68]

We would also point out that while caps on rates might seem like a straightforward solution to prevent rate shock for customers, it has several drawbacks. Rate caps could delay necessary investments in infrastructure and maintenance, leading to higher costs in the future. Artificial caps on rates can distort market signals leading to lower priority on energy efficiency. Caps would also limit the available revenue needed to maintain and upgrade the system, potentially compromising service quality and reliability. Instead of rate caps, a more balanced approach that involves customer assistance programs to help those most affected by rate increases while also ensuring PGE can maintain its infrastructure is more appropriate.

[68] *In the Matter of Portland General Electric Company's Proposal to Reprice its Service in Accordance with the Provisions of SB 1149*, Docket UE 115, Order 01-842 at 4 (Sep 28, 2001).

Q. Are there other mechanisms to address affordability and residential customer impacts?

A. Yes. As we detail extensively above, there are many options to address affordability and residential customer impacts, including through the customer class and rate spread design process. While PGE recognizes that it cannot wholly avoid the impacts of raising rates, the Company is exercising its best efforts to minimize and smooth the impacts of necessary new investments wherever possible. PGE's approach to managing its overall capital program for the benefit of customers is addressed in more detail in Exhibit 1100 – Capital Planning and Business Model.

A. Staff's Rate Cap Proposal

Q. Please provide more detail regarding Staff's rate cap proposal.

A. In Direct Testimony, Staff merely states that, through some combination of revenue requirement and rate spread, "the residential class" should experience "an increase or no more than three percent of revenue requirement."[69] To clarify further, PGE asked Staff to explain (a) to whom exactly the cap would apply; (b) how the cap would work; and (c) why a 3% cap is appropriate.[70]

Q. Does Staff explain the scope of its proposed rate cap?

A. Yes. With respect to the scope of the cap's application, Staff explains that "the three percent limit is intended to apply . . . to PGE's residential class of customers[.]"[71] Staff clarifies that, for the moment at least, "the three percent 'cap' excludes power costs and is limited to base rates."[72]

[69] Staff/200, Scala/38.
[70] Exhibit 1201, OPUC Response to PGE DR 1.
[71] *Id*.
[72] *Id*.

Q. Does Staff explain how they arrived at a 3% cap?

A. In part. When asked "why Staff thinks it is appropriate for all residential customers to receive the proposed 3 [percent] cost cap," Staff objects that the question was "overly broad and burdensome, considering the extensive data it would necessitate providing."[73] Nonetheless, Staff goes on to suggest that the cap reflects the net results of its own adjustments.[74] From Staff's perspective, this means that, "if Staff's adjustments are adopted by the Commission," then "there will be no marginal impact from the cap on other customers[.]"[75] While Staff asserts that any rate increase above this cap "is likely unreasonable and unduly burdensome,"[76] it appears that Staff arbitrarily set this cap based on the result of its combined adjustments.

Q. Does Staff propose a similar cap in other general rate cases?

A. While Staff proposed a cap for a different utility, it was not similar. Staff proposed an identical structure for a residential cap in PacifiCorp's pending general rate case, UE 433.[77] In that case however, Staff proposed an 8% cap. At no point does Staff provide support for its proposed cap or explain if they performed any analysis to show why they would recommend different cap levels for PacificCorp and PGE.

Q. Did Staff explain how the proposed rate cap would work if the Commission does not accept all of Staff's adjustments?

A. No. With respect to how the cap would work if the Commission does not accept all of Staff's adjustments, Staff is significantly less clear. On the one hand, Staff suggests that the

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[73] Exhibit 1201, OPUC Response to PGE DR 1.
[74] *Id.* (stating that Staff "set the cap at roughly the level of the residential increase" after applying its proposed adjustments and the current residential class ratio).
[75] *Id.*
[76] *Id.*
[77] *In the Matter of PacificCorp dba Pacific Power Request for a General Rate Revision*, Docket UE 433, Staff/300, Scala/31 (Jun 28, 2024).

Commission could use the cap in a vague, high-level way, as "context to inform how it considers the practical impacts of the general rate case[,]" as a "tool within larger and evolving affordability frameworks and policies as they relate to ratemaking principles," and as "a residential affordability reference point[.]"[78]

On the other hand, Staff also seems to recognize that a cap is, at its core, "a simplified upper bound" on rates.[79] Logically, capping residential rate increases at 3% can be achieved in one of two ways: either by reducing the Company's recovery for prudently incurred cost or by redistributing cost allocation among other customers. Indeed, Staff refers to these two approaches "as a rate spread cap" or "reducing the Company's revenue requirement[.]"[80]

Q. Does Staff recommend that the Commission meet the cap using either rate spread or revenue requirement reductions?

A. Yes. Staff indicates that the Commission could choose either to modify rate spread or reduce PGE's revenue requirement to achieve a 3% residential rate cap. Staff states that "[r]ate spread caps have commonly been proposed and used in Oregon."[81] Alternately, the Commission could "instead establish PGE's revenue requirement in a manner that satisfies the limit," though Staff recognizes that "there could be a marginal financial impact to the Company."[82]

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[78] Exhibit 1201, OPUC Response to PGE DR 1.
[79] *Id.*
[80] *Id.*
[81] *Id.*
[82] *Id.*

Q. Does Staff identify any legal concerns with reducing PGE's revenue requirement to meet a 3% cap?

A. No. If the Commission chooses to reduce PGE's revenue requirement to meet Staff's proposed cap, Staff merely notes that "this would be less precedential."[83] Staff has, it claims, "found no evidence that the use of such a threshold should be deemed inappropriate or illegal."[84]

Q. Do you agree that the Commission can reduce recovery of prudently incurred costs in order to meet an arbitrary rate cap?

A. No. While this issue will be fully addressed in legal briefing, Oregon is a cost-of-service state and as such, Staff's proposal would disregard the Commission's duty to set rates based on prudently incurred costs to serve. While Staff correctly notes that ORS 757.230 grants the Commission flexibility to structure classes of service to address affordability, it is our understanding that ORS 756.040 continues to require cost-of-service rate-setting.

B. CUB's Rate Cap Proposal

Q. Please provide more details on CUB's rate cap proposal.

A. CUB urges the Commission to adopt a rate cap mechanism based on housing legislation.[85] CUB claims that, because the legislature's rent control established a policy around increases in housing costs, and "[b]ecause utilities are a part of the cost of housing," a similar triggering mechanism for energy rate increases is appropriate.[86] Specifically, CUB proposes that, if rates increase above 10% or 7% + CPI, then the Commission should "require application of tools to mitigate that shock"—namely: (1) deferring/phasing in rate increases; (2) setting rates at the

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[83] *Id.*
[84] *Id.*
[85] CUB/100, Jenks/74.
[86] *Id.* 74-75.

lowest reasonable rate; and (3) requiring the utility to propose and implement other unspecified rate mitigation measures.[87]

Q. Does PGE agree CUB's use of the legislative cap on rental increase is an appropriate justification for its proposal in this case?

A. No. Put simply, energy is not the same as housing. CUB's proposal does not recognize glaring differences between the heavily regulated energy utility industry and the free market rental housing sector. Unlike the rental housing market, energy utilities operate under strict cost-of-service regulations that allow them to recover only the prudent costs approved by the Commission.

In contrast, the rental housing market is driven purely by the forces of supply and demand. Landlords have the ability to raise rents at their discretion when demand outpaces supply, even if their own costs remain unchanged. This dynamic is completely different for energy utilities, which are legally bound to provide essential services at fair rates based on their approved operating costs.

Trying to apply rental housing market principles to regulated utilities is not an apt comparison. The stringent oversight and rate case process governing energy company price changes create a fundamentally different paradigm that CUB's proposal disregards. We must recognize this critical distinction to have a productive discussion about fair utility rates.

Q. Is delaying recovery of prudently incurred costs of providing service appropriate?

A. No. While the legal issues inherent in delaying recovery of prudently incurred costs will be addressed in legal briefing,[88] delaying rate changes penalizes utilities for making necessary

[87] *Id.* 72-73, 75.
[88] ORS 756.040(1).

investments that provide essential services. Moreover, as discussed in more detail in Exhibit 1100 – Capital Planning and Business Model, a utility's risk profile may be adversely affected when a heightened level of capital investment and Commission-authorized under-recovery prevents adequate recovery of invested capital. PGE has made—and continues to make—substantial investments to serve customers reliably, safely, and consistent with applicable laws and regulations. Capping or delaying PGE's recovery of prudent costs would make it more difficult for the Company to access capital at reasonable costs to make continued investments that serve Oregon customers.

Q. Does the Commission already set the lowest reasonable rates to serve customers?

A. Yes. The Commission is already tasked with balancing the needs of customers and shareholders, while ensuring that there is an adequate opportunity to recover prudently incurred costs. CUB's exhortation to set rates at "the lowest reasonable rate" is precisely the same standard that the Commission always has applied.[89]

Q. Does CUB recognize alternate ways to mitigate rate impacts on residential customers?

A. Yes. The Commission has historically considered rate impacts on a case-specific basis using rate spread and rate design tools. As CUB acknowledges in its testimony, these issues are often resolved through stipulations which provide additional flexibility to fashion solutions. While CUB testifies that it does not believe stipulations are the best way to resolve rate increase concerns, CUB has supported these stipulations in other cases.[90]

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[89] CUB/100, Jenks/72.

[90] *See*, e.g., *In the Matter of Pacificorp, dba Pacific Power, Request for a General Rate Revision*, Docket UE 374, Order No. 20-473 at 2 (Dec. 18, 2020).

Q. Please respond to each of CUB's proposed actions following over-threshold rate increases:

A. CUB's proposes the following actions where costs increase above the proposed cap threshold:

1. Delaying recovery for costs "that do not need to be recovered during the winter months."[91] As stated, the Company does not seek recovery of unnecessary costs.
2. Requiring PGE to submit a plan to mitigate rate shock, including customer education efforts about bill discount programs, energy efficiency, and "other options[.]"[92] PGE proactively enrolls customers in the bill discount program and communicates with customers about energy efficiency options. PGE also collaborates with customers on payment assistance programs to reduce disconnections wherever possible and offers the previously mentioned Equal Pay billing option that allows customers to better anticipate their bill each month.
3. Implementing a disconnection moratorium for 6 months following a rate increase.[93] While PGE is open to discussing disconnection moratoria, the Company must emphasize that such efforts ultimately increase costs for customers. Inflating arrearage balances and write-offs create more expenses that are then borne by other customers.
4. Reporting arrearage data for 12-months following a rate increase.[94] PGE is unclear how this effort would reduce rate impacts for customers, and indeed increases the Company's regulatory burden and associated costs.

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[91] CUB/100, Jenks/77.
[92] *Id.* 78.
[93] CUB/100, Jenks/78.
[94] *Id.*

5. Suspending or reducing amortization of "certain deferred accounts or other single issue ratemaking mechanisms[.]"[95] Separate rules govern deferred accounting and mechanisms such as annual power cost updates; it is unclear whether or how CUB's proposal would actually be implemented consistent with applicable law.

Q. Even if CUB's rate cap proposal were permissible, would it be appropriate to adopt such a policy?

A. No. It would not be reasonable to adopt this for two key reasons. CUB's proposal that rates above a threshold be deferred to the following year would create a growing debt for customers, as it merely defers expenses to be borne by future customers.

Q. CUB points to testimony from Commissioner Beyer in 2003, suggesting that the Commission has discretion to adopt a variety of rate mitigation tools.[96] How do you respond?

A. As an initial matter, the testimony CUB cites from more than two decades ago concerns legislation that was not in fact adopted by the Oregon legislature. As CUB points out, Commissioner Beyer's testimony made clear that the Commission "has discretion to set the lowest reasonable rates for a utility[.]"[97] However, Commissioner Beyer also makes clear "that reasonable rates must provide revenue only for prudent expenses and investment."[98] As Commissioner Beyer explained, where costs have been prudently incurred, then reasonable rates must provide a reasonable opportunity to recover such costs.

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[95] *Id.*
[96] HB 3575, 72nd Leg., Reg. Sess. (Or. 2003).
[97] *In re Idaho Power Co. Request for a General Rate Revision*, Docket UE 426, CUB/103, Jenks/2 (Mar 25, 2024).
[98] *Id.*

VII. Qualifications

Q. Kristen Sheeran, please summarize your qualifications.

A. I received a Bachelor of Arts in Economics and Political Science from Drew University and PhD in Economics from American University. I began working at PGE in October 2021 and am responsible for strategic planning, sustainability, and resource planning, including the Integrated Resource Plan, Clean Energy Plan, Distribution Resource Plan, Transportation Electrification and Multi-Year Plan, and Environmental, Social and Governance (ESG). Prior to joining PGE, I served as Energy, Climate, and Transportation Policy Advisor to Oregon Governor Kate Brown. Prior to that, I held Director roles at 3Degrees Group, Climate Solutions, was Vice President of Knowledge Systems focused on ESG at EcoTrust and was the Founder and Director of Economics for Equity and Environment Network. I have also published numerous scholarly articles and a book on climate and energy policy.

Q. Jake Wise, please summarize your qualifications.

A. I received a Bachelor of Science in Business Administration from University of Colorado Boulder and a Master of Sustainable Business Management, MBA from Presidio Graduate School. I joined PGE in January 2019 working as liaison on energy efficiency and outreach and am currently the Manager Strategy and Planning, Energy Savings and Affordability where I work on energy efficiency partnership and affordability program support for customers. Before joining PGE, the majority of my career has focused on data solutions to support energy sector program evaluation (measurement and verification) and other analytics.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1201	OPUC Response to PGE DR 1

Date: August 2, 2024

TO:
Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC-0306
Portland, OR 97204

FROM: Michelle Scala, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 435 – PGE Data Request No. 1

PGE Data Request No. 1:

Please refer to Staff/200, Scala/38. Regarding Staff's recommendation of a cap on a residential increase of 3% of PGE's overall revenue requirement proposal:

a. Please clarify and provide an illustrative example of what Staff means by a cap based on overall revenue requirement and explain whether that cap applies to: all residential customers, is based on the proposed incremental revenue requirement increase, includes power costs or other known and measurable changes to annual tariffs?
b. Please explain how Staff intends the mechanics of the cap to work.
c. Please describe why Staff thinks it is appropriate for all residential customers to receive the proposed 3% cost cap?
    - Provide any analysis performed by Staff in developing this proposal.
    - Provide all research relied upon by Staff for this proposal showing where other Commissions or utilities have applied a similar cap.
    - Describe in narrative form the analysis performed by Staff of any potential financial impacts to PGE and other customer classes when developing Staff's proposed cap. Provide copies of all documentation and research used for Staff's analysis.
d. Please provide all analysis and work papers with formulae intact of the estimated cost impacts to all other customer classes from Staffs proposed 3% cap.
e. Reference Staff's Proposed Rate Spread in Table 4 of Staff 900. Please describe how Staff's proposal for a 125% cap will work with Staff's proposal in Staff/200 for a 3% cap. Provide all workpapers and analysis performed by Staff to develop the interplay of these proposals.
    - Specifically describe and show the reconciliation of the 3% cap proposal with PGE's marginal cost study and Staff's proposed rate spread in Table 4 of Staff/900.

OPUC Data Response No. 1:

Staff's recommendation (described in Exhibit Staff/200, Scala/38 and referenced in the Company's DR 1), reads "[t]he final determination of rate spread in conjunction with revenue requirement ensures that the residential class sees an increase of no more than three percent of revenue requirement.

a. Functionally, the three percent limit is intended to apply to the entire portion of the UE 435 incremental base revenue increase assigned to PGE's residential class of customers at the conclusion of this proceeding. At this time, the three percent "cap" excludes power costs and is limited to base rates. The limit is inclusive of Staff's revenue requirement adjustments provided in its filed UE 435 Opening Testimony.

   Illustratively, the three percent limit would function as an affordability threshold for the Commission to consider when evaluating the collective terms of UE 435 issues. For example, if the combined effect of the UE 435 proposal(s) before the Commission, including but not limited to rate spread, return on equity (ROE), and revenue requirement, result in an increase to residential revenues greater than the threshold, then Staff has flagged that there is a heightened risk to residential affordability and energy justice concerns. Thus, the Commission may use this context to inform how it considers the practical impacts of the general rate case on residential communities and whether further refinements on any or all of the issues are warranted to minimize human harms.

b. While Staff's three percent limit was informed by the estimated combined effect of Staff's Opening Testimony revenue requirement adjustments and rate spread cap and floor proposal, the recommendation is provided within an energy justice context to be used by the Commission as a simplified upper bound when considering the collective impacts of the case on residential affordability. Staff distinguishes that the limit is not intended as a formalized mechanism to establish a specific treatment of costs. Rather setting a threshold serves as a tool within larger and evolving affordability frameworks and policies as they relate to ratemaking principles. It should not be assumed that adopting the threshold in this case would necessarily result in excess revenue requirement being spread across nonresidential schedules. Rate spread represents just one of many levers influencing the outcomes of this proceeding. Thus, using the three percent threshold as a residential affordability reference point, benchmarked to Staff's UE 435 adjustments, is discretionary to the Commission as it makes interrelated decisions across elements of this proceeding.

c. Staff objects to this question on the basis that it is overly broad and burdensome, considering the extensive data it would necessitate providing. This is compounded by the diverse aspects of the rate case that Staff would be expected to align at this moment to achieve Staff's proposal of a three percent limit on residential impacts via rate spread and address residential affordability as a matter of policy.

Notwithstanding, as noted, the three percent value of Staff's proposed limit was largely informed by Staff's UE 435 Opening Testimony rate spread (Staff Exhibit 900) and revenue requirement adjustments (Staff Exhibit 300). While Staff did not calculate the rate spread based on all of its adjustments, Staff estimated the rate impact to residential customers by finding the overall revenue increase from its proposed adjustments and applying the residential class's ratio compared to the average increase in Staff's proposed rate spread. Staff then set the cap at roughly the level of the residential increase from this method.

That said, Staff again reiterates that this limit was provided in the context of Staff's energy justice testimony and is not principally a mechanism to necessarily restrain rate spread. Inclusion of a limiter on residential impacts was supported by Staff's review of energy insecurity and affordability metrics, including but not limited to arrearages, disconnections, and IQBD measures which revealed significant concerns around residential customers' ability to afford their monthly energy bills. This assessment was further grounded by the Company's Energy Burden Assessment findings and qualitative statements provided by PGE's residential customers in the UE 435 Public Comment period. To these ends, Staff sought to provide a threshold, informed by its Opening Testimony analysis and adjustments as a tool for the Commission to use in a holistic evaluation of the rate case as it relates to residential impacts

Staff proposes this rate increase threshold for the Commission's consideration as Staff believes that both its revenue requirement adjustments and rate spread are reasonable, but any increase above Staff's three percent limit is likely unreasonable and unduly burdensome. Staff only proposed a cap for residential customers as they have seen some of the highest rate increases in recent years and their consumption of energy is directly related to health, safety, and the facilitation of modern life. The Commission has been given explicit authority to make decisions based on affordability (ORS 757.230).

Rate spread caps have commonly been proposed and used in Oregon.[1] If the Commission chooses to apply the three percent limit as a rate spread cap, this would not be a novel proposal. If the Commission chooses to authorize the limit by maintaining a rate spread while reducing the Company's revenue requirement, this would be less precedential. Staff offers the options both to apply the cap at all and if adopted, how to administer it to the Commission and has found no evidence that the use of such a threshold should be deemed inappropriate or illegal.

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[1] See Order No. 22-491.

Staff did not perform a financial analysis on the impact of the three percent limit. Hypothetically, if the limit is applied as a rate spread cap, there would be no marginal financial impact to the Company from its adoption. However, there could be a marginal financial impact to any customer classes who bore the additional portion of the revenue requirement spread as a direct result of the cap if applied exclusively in this manner. That said, if the Commission were to instead establish PGE's revenue requirement in a manner that satisfies the limit, there could be a marginal financial impact to the Company. The marginal financial impact is impossible to calculate as it would be based on the final revenue requirement after all other adjustments are made. Staff found no additional value in completing this analysis as there were too many unknowns and too many scenarios by which the Commission may choose to authorize the limiter.

d. As stated above, if Staff's adjustments are adopted by the Commission, the cap was constructed such that there would be little to no impact to the Company or other customers. The marginal impact of the cap will depend on which adjustments are adopted by the Commission and how the Commission decides to implement the cap.

e. Again, Staff's proposed three percent cap is based on Staff's proposed adjustments and rate spread. If both of these are adopted, there will be no marginal impact from the cap on other customers nor will it alter Staff's rate spread proposal in a material way. If there are slight adjustments to Staff's rate spread proposal needed to facilitate the cap, then Staff is open to consider these adjustments.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Greg Batzler
Stephanie Meeks

August 14, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Greg Batzler. My position is Senior Regulatory Consultant, Regulatory Affairs. My qualifications appear in PGE Exhibit 200.

My name is Stephanie Meeks. My position is Regulatory Consultant, Regulatory Affairs. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address proposed adjustments raised by the Staff of the Public Utility Commission of Oregon (Staff), the Oregon Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to PGE's 2025 Test Year revenue requirement.

Q. Has PGE updated the revenue requirement requested in this proceeding?

A. Yes. As we discuss further in Section II below and as provided in PGE Exhibit 1301, PGE has reduced its January 1 base business request in this case by approximately $18 million, inclusive of the Constable Battery Energy Storage System (BESS), which results in a revised base business request of $190.5 million, or 6.88% increase for base business.[1]

[1] It is a 6.3% increase relative to the total price change for 2025.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have 13 sections:

- Section II – Overview & Summary
- Section III – Rate Base Mismatch Calculation
- Section IV – Cost of Removal
- Section V – Investment Tax Credits (ITC)
- Section VI – Anderson ITC
- Section VII – Accumulated Deferred Income Taxes (ADIT)
- Section VIII – Oregon Corporate Activities Tax (OCAT)
- Section IX – Cash Working Capital (CWC)
- Section X – Fuel Stock & Materials and Supplies
- Section XI – Other Revenue – Joint Pole and Steam Revenue
- Section XII – PGE Grants
- Section XIII – Capital Attestations
- Section XIV – Qualifications

II. Overview and Summary

Q. Please summarize the issues PGE is responding to in this testimony.

A. Parties raise the following issues, and adjustments, which we are responding to within PGE Exhibit 1300:

1. Staff and AWEC propose changing PGE's end of period (EOP) method for calculating rate base. Staff proposes a mismatch of PGE's filed December 31, 2024 balance for gross plant with a theoretical 2025 average of monthly averages (AMA) amount for accumulated depreciation. AWEC proposes using an AMA method based on January 1, 2024 through December 31, 2024 rate base.
2. AWEC proposes an adjustment for PGE's cost of removal (COR) assumptions arguing that PGE's method should be consistent with Docket No. UM 2152.
3. All Parties disagree with PGE's proposal to return the value of battery investment tax credits to customers over five years through a separate tariff schedule.
4. AWEC recommends that PGE opt out of normalization for the Anderson Readiness Center (Anderson) Battery Energy Storage System (BESS) ITC and return the value to customers.
5. AWEC proposes various adjustments to PGE's accumulated deferred income taxes (ADIT) associated with production tax credit (PTC) carryforwards, Boardman COR, incentives, and Docket No. UE 408 deferred amounts.
6. AWEC proposes to adjust PGE's OCAT forecast based on a calculation they performed using PGE's 2022 tax return and 2023 accrued OCAT amounts.
7. Staff proposes to adjust the service lag days in PGE's lead lag study and to modify calculation of PGE's working capital amounts by removing depreciation and

amortization expense from the total operating expenses used to determine amounts included in rate base.

8. Staff proposes to adjust PGE's gas and oil fuel stock and to remove PGE's CO2 allowance fuel stock from rate base.
9. Staff proposes to adjust PGE's materials and supplies balances using an average of historical averages.
10. Staff proposes to increase PGE's joint pole and steam sale revenue based on a simple three-year average for these other revenue categories.
11. Staff recommends the removal of $700,000 associated with PGE's federal grant funding, arguing that these expenses may be federally reimbursable and thus should not be charged to customers.
12. AWEC proposes an attestation process for all PGE capital projects in which the final costs of the projects are documented with potential rate adjustments if the costs for any given project is less than the prudently determined amount.
13. Staff proposes PGE adjust the base amount of OPUC fees to the current effective rate of 0.45%.

Q. Does PGE agree with any of the above adjustments proposed from the Parties?

A. Yes. PGE agrees to the following adjustments proposed from the Parties:

1. PGE agrees to modify our proposal to return BESS ITCs to customers. We discuss this further in Section V.
2. PGE agrees to opt out of tax normalization for the ITCs associated with the Anderson BESS.

3. PGE agrees to remove the ADIT associated with Boardman COR and adjust the ADIT associated with incentives, consistent with AWEC's recommendation.
4. While we disagree with the basis of Staff's argument, PGE agrees to remove the rate base amount associated with CO2 allowances, as our current expected balance at December 31, 2024 will be at or close to zero.
5. PGE agrees with Staff's proposal to maintain the current OPUC fee rate of 0.45%.

Q. Please summarize PGE's position regarding the remainder of Parties proposed adjustments.

A. PGE responds as follows to the remaining issues from Parties that are addressed in the following testimony:

1. PGE fundamentally disagrees with Staff's rate base mismatch proposal and AWEC's prior year average rate base proposal for reasons described below. Ultimately, Staff is seeking to disconnect accumulated depreciation amounts from gross plant amounts, while AWEC proposes an AMA rate base amount that is <u>one year prior</u> to PGE's test year in this case. Both proposals effectuate a test year rate base guaranteed to be systematically below PGE's actual rate base as of January 1, 2025 or at any point during the test period. Staff's and AWEC's proposals are simply bad policy and should be rejected by the Commission.
2. AWEC is incorrect in their assertion that PGE's treatment of COR amounts is inconsistent with PGE's approved depreciation study (UM 2152). PGE's treatment of COR is accurate and annually reviewed by our external auditor.

3. PGE has updated PTC carryforward amounts to remove the forecast 2024 generated PTCs. PGE has also updated the amount we expect to utilize in 2024, based on PGE's current expected tax position for the year.
4. PGE disagrees with AWEC's ADIT proposal for UE 408 deferred amounts. These amounts are handled entirely outside of PGE's base rates and the current treatment and collection of these amounts was previously decided through an all-party settlement adopted by the Commission.
5. PGE recommends an adjustment to the 2025 forecast OCAT amount based upon the most current expectations for 2024 amounts, while also providing support for the overall amount of OCAT expense in comparison to PGE's total revenues.
6. PGE is correctly calculating amounts within its lead-lag study and correctly including depreciation and amortization expense in the total operating expense base used to determine PGE's working capital requirements.
7. PGE's fuel stock balances are correctly calculated, provide effective insurance against market disruptions and/or reliability contingency events, and provide customers economic benefits within PGE's net variable power cost forecast.
8. PGE's materials and supplies balances, which are predominantly comprised of transmission and distribution related materials, have seen extreme inflation that has greatly outpaced the core consumer rate and PGE's current balance of materials and supplies is greater than amounts included in the test year.
9. PGE's other revenue forecast is the best information and expectation we currently have for 2025 and when removing outliers from historical averages, PGE's forecast is consistent with recent results.

10. Staff has not provided a reasonable basis for their proposed reduction to associated grant costs. In fact, PGE's current estimate for the 2025 non-reimbursable O&M cost share associated with grants pursued on behalf of customers is approximately $3 million greater than amounts forecast in this case.
11. Should the Commission decide an attestation process is needed, PGE proposes for projects placed into service between October 1 and December 31, 2024, a capital attestation process for projects greater than $5 million.

Q. Have any other issues been raised by parties that concern PGE's overall revenue requirement that merit a response from PGE?

A. Yes. AWEC raised "general concerns" regarding PGE's revenue requirement stating that PGE is not following traditional ratemaking standards, relies on methods "incompatible with Oregon's concept of a test period,"[2] provided analysis that is "meaningless when evaluating the reasonableness of its revenue requirement"[3] and that PGE has abandoned the concepts of "used and useful" and "known and measurable". Following these assertions, AWEC recommended the Commission find that PGE has failed to meet its burden of proof.

Q. How do you respond to AWEC's assertion that PGE is not following traditional ratemaking standards?

A. AWEC states that a traditional revenue requirement study starts with utility's actual operating results of a historical period and making sequential adjustments to reflect the increase proposal. However, AWEC neglects to mention that PGE provided historical actuals to compare against its 2025 test year through the standard data request process and as work paper support included with each piece of testimony provided. AWEC appears to be describing the

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[2] AWEC/100, Mullins/7, at 6.
[3] *Id.* at 15.

use of a historical test year, while Oregon has standardized the use of a forward test year for many decades.

Q. How do you respond to AWEC's assertion that the analysis PGE provided is meaningless?

A. We fundamentally disagree. Comparing our 2025 test year expense to 2024 budgeted amounts is very meaningful as PGE's 2024 budget reflects the outcome from PGE's 2024 general rate case. As we demonstrated in PGE Exhibit 200, Table 2, PGE's 2024 budget very closely aligns with the outcome of UE 416. It is not reasonable for AWEC to seek to essentially re-litigate the results of UE 416 rather than perform a review of PGE's expected costs in this case. Regardless, PGE's work papers within its initial filing provides full accounting string details for three years of actual costs (i.e., 2021-2023), PGE's 2024 budget, and PGE's 2025 test year. It is unclear why AWEC largely chose to ignore this information.

Q. Were other Parties able to utilize PGE's actuals for the review of PGE's request?

A. Yes. While we believe 2024 is the appropriate comparison for this rate review proceeding, Staff was able to compare PGE's 2025 forecast to 2023 actuals throughout PGE's operating accounts.

Q. Does PGE's rate review filing adhere to the regulatory standards of "used and useful" and "known and measurable"?

A. Yes. PGE's end-of-period rate base fully complies with ORS 757.355 and PGE's test year expense and rate base are representative of the period during which rates will be in effect. PGE's response to over 1,000 data requests in this proceeding provides extensive details justifying PGE's 2025 forecasted expenses and describes the known and measurable changes from both 2023 actuals and PGE's 2024 budget. Further, PGE's initial filing discusses known and measurable changes from PGE's 2024 budget that is based upon the 2024 test year amounts from a fully adjudicated proceeding (Order 23-386 in UE 416).

Q. How do you respond to AWEC's assertion that PGE has not met its burden of proof?

A. PGE fundamentally disagrees with the assertions made by AWEC. PGE's incremental costs in this case were fully supported within our opening testimony and the arguments brought by AWEC and other parties within their opening testimony are comprehensively addressed within PGE's reply testimony. In addition, PGE's responses to over 1,000 data requests provides further support and description.

Q. Please provide an overview of the revenue requirement originally requested in this rate review.

A. As addressed in PGE's direct testimony, the revenue requirement reflects the 2025 forecast calculation to base rates for January 1, 2025. PGE's request in direct testimony was for a base business increase of $202.0 million[4] or 7.3%, inclusive of the Constable Battery Energy Storage System (BESS) (Constable). While Constable was included in this base business amount, PGE also provided a breakdown in a separate calculation to show the revenue requirement amounts for both Constable and the Seaside BESS (Seaside), with anticipated in-service dates of December 31, 2024 and June 30, 2025, respectively. Seaside was not included in the base business rate but rather in a separate proposed tracker.

Q. Is PGE be providing an updated revenue requirement as part of this testimony?

A. Yes. PGE Exhibit 1301 provides an updated revenue requirement, which includes the changes and recommendations discussed within PGE's reply testimony, including impacts from PGE's May 1, 2024 plant update provided earlier in this proceeding, and forecasted net variable

[4] PGE notes that subsequent to our initial filing, the estimated load benefits attributable to NVPC was refined.

power costs (NVPC) as of July 15, 2024 provided in Docket UE 436. Table 1 below provides the revenue requirement impacts of the proposed adjustments and PGE's reply testimony where these adjustments are discussed.

Table 1
Adjustments to Revenue Requirement (000s)

Adjustment	**Testimony**	**Rev Req Impact**
May 1 Plant Update[5]	Exhibit 1300	3,097
CO2 Allowances	Exhibit 1300	(195)
Boardman COR ADIT	Exhibit 1300	(585)
Accrued Incentive ADIT	Exhibit 1300	(489)
PTC Carryforwards	Exhibit 1300	(4,937)
OPUC Fees	Exhibit 1300	685
OCAT	Exhibit 1300	(1,905)
ITC in Constable RevReq	Exhibit 1300	(6,811)
Memberships	Exhibit 1400	(49)
Meals & Entertainment	Exhibit 1400	(148)
Amazon Pay	Exhibit 1500	(27)
TriMet UM 1811 Capital	Exhibit 1500	(0)
Clearwater Fee	Exhibit 1700	(2,080)
ROE	Exhibit 1800	(5,210)
Cost of Debt	Exhibit 1800	495
Total		**(18,159)**

Q. What is the impact to PGE's revenue requirement request in this proceeding from the above adjustments?

A. Including the adjustments in Table 1, PGE's base business revenue requirement request in this case, inclusive of Constable is now $190.5 million, or 6.88%.[6]

[5] Inclusive of changes to Constable.
[6] The increase to base rates is 6.88%, however, the base rate contribution to the total increase in 2025 is 6.3%.

III. Rate Base Calculation

Q. Describe how PGE calculates rate base plant balances and depreciation for the Test Year.

A. PGE's rate base plant calculation starts with plant as of December 31, 2023, and adds capital additions through December 31, 2024. Depreciation expense is then annualized for the 2024 plant additions to reflect a full year of depreciation expense for these assets. PGE adds the annualized depreciation to the accumulated reserve to reduce the 2024 plant additions to match investments' costs with their corresponding benefits.

Q. Do any Parties propose modified approaches to calculating capital in rate base?

A. Yes. Staff and AWEC both propose modified approaches to calculating rate base. We address each in turn.

A. Staff's Mismatch Capital Proposal

Q. How does Staff propose calculating rate base?

A. Staff recommends a calculation of rate base that mismatches both years and method. Staff reduces PGE's rate base using a "modified" thirteen-month AMA approach for accumulated depreciation from December 2024 to December 2025, while leaving PGE's December 31, 2024 gross plant balance unchanged. Essentially, Staff proposes to update the Company's test year rate base for 2025 to reflect subtractions, but not account for any additions.

Q. Does PGE believe that Staff's approach is fair or reasonable?

A. No. Staff's one-sided approach to rate base valuation artificially devalues PGE's rate base that is in-service to customers in the test year. Staff states their "proposal is to use a modified version of the AMA calculation that was used by the Commission for many years."[7] However, the "modification" that Staff proposes fundamentally alters what is commonly referred to as AMA rate base, creating a mismatch of rate base treatment between gross plant and accumulated depreciation, which systematically devalues PGE's rate base.

Q. How does the value derived from Staff's approach compare to PGE's actual rate base value at the start of PGE's test year?

A. Including Constable, PGE's forecasted total rate base as of December 31, 2024 (i.e., one day prior to the beginning of PGE's test year) is approximately $7,446 million. However, because PGE annualizes its 2024 depreciation expense for plant additions and credits rate base with the full value, our *requested* test year rate base inclusive of Constable is approximately $7,400 million. Staff's recommendation, of adding an additional half year of accumulated depreciation to PGE's rate base, would result in a test year rate base of approximately $7,157 million, which is approximately $290 million below PGE's forecast total rate base as of December 31, 2024 and $244 million below PGE's test year rate base request. Based on PGE's current request in this case, the impact of Staff's proposal would result in an approximate 60 basis point reduction from PGE's authorized ROE. That is, prior to any other results in 2025, PGE's starting point would be 0.6% below the ROE authorized in this proceeding.

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[7] Staff/900, Stevens/30, at 18-19.

Q. Staff also proposed the rate base mismatch method in PGE's prior general rate case (UE 416) in which PGE raised many issues with the approach. Does Staff offer any new arguments to refute PGE's concerns raised in UE 416?

A. No. Staff's testimony in this proceeding attempts to refute the arguments PGE made in UE 416; however, Staff provides no new arguments or reasoning for their unbalanced proposal. The prior arguments made by PGE, which Staff attempts to refute are as follows:

1. Staff's method has never been used in Oregon or by any other State Commission;
2. Staff's proposal is fundamentally flawed as it creates a mismatch between years and methods;
3. Staff's method as proposed violates tax normalization rules, which require consistency in the calculation of tax expense, book depreciation expense, accumulated book depreciation, and accumulated deferred income taxes (ADIT);
4. Reflecting financial statements in the manner Staff proposes would violate the Generally Accepted Accounting Principles (GAAP) of periodicity and consistency;
5. The adoption of Staff's method by the Commission will guarantee that PGE systematically underearns its authorized return on equity (ROE); and
6. The adoption of Staff's method will likely signal to investors that PGE is a riskier investment relative to our peers.

As we will demonstrate below, there is no basis for Staff's proposal. Additionally, we provide here as PGE Exhibit 1302 our reply and surrebuttal testimony provided in Docket UE 416 on this topic.

Q. Is Staff's mismatched rate base adjustment consistent with Commission precedent?

A. No. The method historically used by the Commission matched the components of rate base to calculate an average-monthly-average over the test period. This was the method first adopted in Commission Order No. 79-055 and is <u>not</u> what Staff proposes in this case. More broadly, the Commission recently reiterated that depreciation and regulatory lag are two sides of the rate base coin: "there is a balance between regulatory lag experienced by the company before plant is included in rate base, and lag experienced by ratepayers associated with the removal of depreciated plant from rates."[8] Staff's proposal disrupts that balance by excluding recovery for additions to plant in 2025 (regulatory lag for utility) but including AMA depreciation for 2025 (no lag for customers). Clearly, any reasonable measurement of the Company's rate base must use the same period for calculating rate base additions *and subtractions.*

Q. Staff states their "primary goal" is that "PGE's rate base reflects the depreciation of its assets over the course of the Test Year."[9] How do you respond?

A. PGE agrees that rates should accurately reflect the Company's rate base. However, Staff's approach only looks at one side of the Company's rate base calculation. As PGE explains in detail in Exhibit 1200 – Capital Program & Business Model, PGE's regulatory lag on invested capital is substantially higher than depreciation levels.

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[8] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, UE 394, Order 22-129 at 35 (April 25, 2022).
[9] Staff/900, Stevens/31 at 8-9.

Q. Additionally, Staff states that with PGE's end of period method, "customers are paying for depreciation expense during the Test Year, but not receiving the benefit of accumulated depreciation over the Test Year."[10] Do you agree?

A. No. PGE's method of annualizing 2024 depreciation expense for plant additions and including that full amount in accumulated depreciation provides customers a corresponding benefit for the incremental depreciation expense included in PGE's test year. Staff's mismatch method seeks to artificially lower rate base by increasing the credit to accumulated depreciation to a mid-year 2025 level of benefit, while keeping the gross plant value in rates at a year end 2024 level of cost.

Q. How does Staff respond to PGE's argument regarding IRS tax normalization rules?

A. Staff states they are not violating IRS tax normalization rules as "The Commission has followed the statutory prohibition on including Test Year investment in rate base for many years and PGE has not prevailed on an argument that the statute creates a normalization issue for the Company that requires a regulatory change."[11]

Q. Do you agree with Staff's reasoning as to why their method doesn't violate IRS tax normalization rules?

A. No. Staff's statement is illogical, as PGE has never used their proposed method. In fact, beyond this confusing statement, Staff does not explain how their modified method does not violate tax normalization rules as defined in Internal Revenue Code, Section 168(i)(9), which require consistency in the calculation of book depreciation expense, tax expense, accumulated book depreciation, and accumulated deferred income taxes. PGE's current method follows the

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[10] *Id.* 29, at 5-6.
[11] Staff/900, Stevens/31 at 14-17.

above requirement for consistency as all elements are based on 2024. Staff's mismatch method does not.

Q. Does Staff's argument regarding the principles of periodicity and consistency make sense?

A. No. Staff states the "methodology would be narrowly applied to the calculation of the required net operating income in this case."[12] This statement is very vague and does not respond to PGE's point regarding these two principles. In summary, the principle of consistency ensures that consistent standards are followed in financial reporting from period to period to ensure financial comparability between periods, while the principle of periodicity establishes that accounting entries should be distributed across the appropriate periods of time. If PGE were to reflect Staff's proposal within any financial statements it would violate these two Generally Accepted Accounting Principles (GAAP). Staff's proposal results in an artificial reduction to PGE's prudently incurred rate base, which could never be reflected in financial reporting, as it is in direct violation of these two Generally Accepted Accounting Principles.

Q. Does Staff's mismatch method better reflect PGE's test period rate base?

A. No. Staff's approach systematically misrepresents PGE's test period rate base. As laid out in Tables 2 and 3 below, PGE's current end of period rate base calculation, adjusted for a full year of depreciation, results in a rate base amount that is persistently below PGE's actual rate base over the year. Staff's mismatch method would simply and arbitrarily exacerbate this result. As shown below, PGE's end of period method has resulted in an average 76 basis points below PGE's authorized ROE; if Staff's method had previously been adopted, that difference

[12] *Id.* at 20-21.

would have grown to a 197 basis point reduction, or an additional 1.2% of downward ROE impact.

Table 2
Basis Point Impact of Authorized vs. Actual Rate Base

Test Year	Docket	Authorized Rate EOP Base	Actual Average Regulated Rate Base(4)	Difference	ROE Basis Point Impact
2015	UE 283	3,785,421	4,009,617	224,196	(80)
2016	UE 294(1)	4,143,584	4,268,624	125,040	(42)
2018	UE 319	4,505,374	4,863,447	358,073	(105)
2019	UE 335	4,744,710	4,949,366	204,656	(57)
2022	UE 394(2)(3)	5,287,621	5,681,061	393,440	(97)
Average 2015-2022 bps impact:					**(76)**

(1) Ratably adjusted for the Carty Tracker
(2) Includes Colstrip
(3) Ratably adjusted for May 2022 price effective date
(4) From PGE's Results of Operations Report

Table 3
Basis Point Impact of Rate Base Mismatch Method vs. Actual Rate Base

Test Year	Docket	Mismatch Rate Base	Actual Average Regulated Rate Base(4)	Difference	ROE Basis Point Impact	Incremental ROE BPS Impact from EOP Method
2015	UE 283	3,635,332	4,009,617	224,196	(139)	(59)
2016	UE 294(1)	3,982,534	4,268,624	125,040	(99)	(57)
2018	UE 319	4,325,314	4,863,447	358,073	(297)	(192)
2019	UE 335	4,560,193	4,949,366	204,656	(179)	(122)
2022	UE 394(2)(3)	5,090,758	5,681,061	393,440	(272)	(175)
Average 2015-2022 bps impact:					**(197)**	**(121)**

(1) Ratably adjusted for the Carty Tracker
(2) Includes Colstrip
(3) Ratably adjusted for May 2022 price effective date
(4) From PGE's Results of Operations Report

Q. What would be the impact of Staff's mismatch proposal for PGE's cost of equity?

A. By advancing the measure for rate base reductions ahead of the time period for rate base additions, Staff's approach results in a systematic punitive impact to PGE's cost of equity. By significantly reducing PGE's ability to compensate investors for the cost of supplying necessary capital, Staff's approach would also undermine PGE's ability to obtain capital at reasonable rates, which ultimately harms customers.

Q. Did Staff provide a calculation or specific amount associated with their rate base mismatch method?

A. No. Staff provided an estimated range for the revenue requirement, stating the adjustment is not final. Further they indicate their methodology, which they describe as applying "one half of PGE's Test Year depreciation value to represent the rough effect of applying an additional half year's worth of accumulated depreciation to […] rate base,"[13] is not the methodology they are proposing PGE use "and this estimate should only be seen as an illustrative example demonstrating the general magnitude of the effect of Staff's proposed methodology."[14] This explanation by Staff creates greater concerns about using their mismatched method for calculating rate base.

Q. Why does Staff's estimated range cause concerns about adopting their mismatched method to calculate rate base?

A. The Commission cannot reasonably rely on the broad estimated adjustment range Staff gives to support use of their rate base calculation method because it does not accurately calculate the magnitude of impacts from their method. Again, the estimated range that Staff provided was not calculated based on the same methodology they are proposing. Staff's adjustment range and their proposal for the method to calculate plant in rate base should be rejected, because their method fundamentally creates a mismatch of rate base plant additions, accumulated reserves, and the balance with the 2025 Test Year's benefits and costs for customers.

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[13] Staff/900, Stevens/33 at 2-5.
[14] *Id.* 32 at 22-23 and 33 at 1-2.

Q. Please summarize PGE's recommendation to the Commission regarding Staff's rate base mismatch proposal.

A. We recommend the Commission reject Staff's proposal. The method Staff proposes is bad policy that if adopted will ensure that PGE systematically underearns on its investments, denying PGE the opportunity to earn its authorized ROE, which will ultimately led to higher borrowing costs for the company and customers.

B. AWEC's Modified Rate Base Calculation

Q. How does AWEC describe PGE's rate base calculation?

A. AWEC refers to PGE's rate base calculation as "a hybrid rate base calculation, including a mixture of variously stated plant balances calculated over the 12-month period of January 1, 2024 through December 31, 2024.[15] AWEC describes PGE's plant-in-service amounts as beginning with December 31, 2023 actual results with the addition of forecasted plant amounts placed into service for 2024. AWEC then asserts PGE's rate base is not based upon December 31, 2024 balances but that PGE assumes all new plant balances were placed in-service on January 1, 2024. AWEC then states the calculation of depreciation expenses and accumulated depreciation over calendar year 2024 are based on inconsistent hybrid values.

Q. Is AWEC correct in describing PGE's plant balances?

A. AWEC is correct that PGE started with December 31, 2023 actual balances and that PGE includes forecasted plant amounts placed into service for 2024. AWEC however incorrectly asserts that PGE assumes plant balances were placed into service January 1, 2024. PGE does not assume this, as clearly evidenced in PGE's Exhibit 200 "GRC Plant Additions Detail"

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[15] AWEC/100, Mullins/12 at 20-21.

work paper that provides monthly plant closings over 2024.[16] The use of a January 1, 2024 date in the data request referenced by AWEC is to calculate and provide customers a full year of accumulated depreciation benefit for new 2024 assets, which *reduces* PGE's December 31, 2024 rate base request.

Q. Is PGE's approach to calculating capital in rate base and applying depreciation new for this general rate case?

A. No. PGE has consistently applied this approach to calculating capital in rate base since Docket No. UE 283 (PGE's 2015 rate case), where Commission Staff indicated they found PGE's method "reasonable."[17]

Q. How do you respond to AWEC's suggestion that PGE's May 1, 2024 capital update calls into question the rate base request in this case?

A. The update provided by PGE on May 1, 2024 included actual close to plant amounts for the first three months of the year plus an updated forecast for the remainder of the year by month and by individual project and functional class. AWEC's statement regarding this update is vague, but the purpose of this update was to provide Parties with the most up to date information we had, while still allowing them over two and a half months of review time prior to filing of testimony. It is unclear why AWEC was confused as to the specific projects, as they were individually provided in that update. Additionally, as mentioned in PGE Exhibit 1200, over 2,000 pages of information on 2024 requested projects has been provided to Parties through discovery. We agree that forecasts, when updated with more known and measurable

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[16] Subsequently updated with actual closings through March 31, 2024 in Attachment 1 to PGE's May 1, 2024 plant update filing in this docket.

[17] *In the Matter of Portland General Electric Request for General Rate Revision*, Docket UE 283, Staff/600, Garcia/1 at 13-16 (Jun. 11, 2014).

information, can change, however, at a $3 million total revenue requirement impact, the impact was relatively minor in comparison to the incremental rate base included in this case.

Q. AWEC goes on to depict PGE's rate base capital additions in a graph.[18] Does this graph accurately reflect PGE's rate base calculation?

A. No. AWEC's graph is not an accurate comparison and should not be relied upon to show PGE's prudently incurred rate base. In particular, AWEC's graph inaccurately shows PGE's rate base as of January 1, 2024. This date is only a proxy used in the calculation of annualized depreciation for new plant additions. As explained above the calculated annualized depreciation expense for new plant additions further reduces the accumulated depreciation, which reduces the December 31, 2024 gross plant to calculate the net capital in rate base.

Q. How does AWEC propose to calculate PGE's test year rate base?

A. AWEC proposes using an AMA method over 12-months from January 1, 2024 through December 31, 2024. AWEC argues that using AMA to establish PGE's capital in rate base is appropriate because the AMA method (1) was designed to measure rate base "over a test period" according to "a consistent set of assumptions,"[19] and (2) the AMA method was previously used by the Commission in the 1970s, during a similarly high-inflation period.[20]

Q. Do you agree that AWEC's proposed AMA method is a reasonable approach for establishing PGE's rate base value for the 2025 test year?

A. No. AWEC's AMA method over the year prior to PGE's test year in this proceeding systematically under values the rate base in service to customers over the period that rates are in effect. AWEC describes the AMA method as an appropriate means for measuring "the

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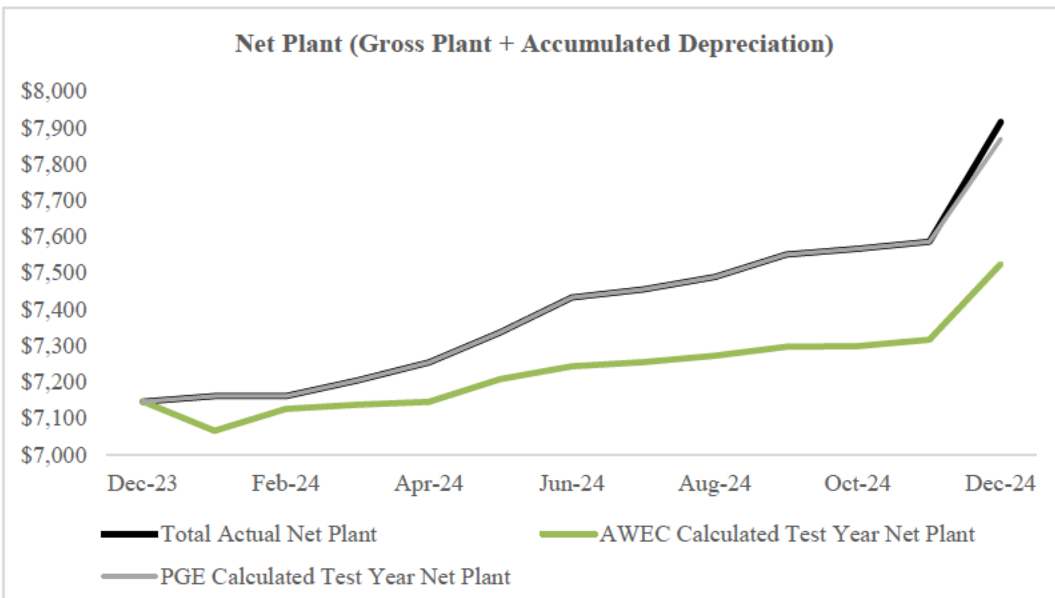
[18] AWEC/100, Mullins/14.
[19] AWEC/100, Mullins/14.
[20] *Id.* 15.

changing level of plant balances over a test period." Except that they are not, in fact, attempting to measure *test year* (calendar year 2025) rate base. This contrasts with PGE's rate base which sets an asset value equal to the expected value of assets that will be in-service to customers on day one of PGE's forecast year (i.e., 2025). Plus, customers receive the full annualized depreciation benefit associated with new assets within accumulated depreciation. Figure 1 below provides a comparison between PGE's expected December 31, 2024 net plant, PGE's December 31, 2024 net plant, inclusive of 2024 annualized depreciation benefits, which is the basis of our test year request, and AWEC's proposal to average 2024 net plant values, to artificially reduce PGE's net plant.

Figure 1



Q. As additional support for their method AWEC notes that the "EOP method tends to inflate rate base relative to the AMA method because plant balances at the end of a period are typically higher than the average balance over the period, although it is common for utilities to propose using the EOP method as an alleged way to reduce regulatory lag."[21] Do you agree?

A. No. AWEC's assertion is based upon a false presumption that an average of 2024 rate base is reasonable to set prices for a 2025 test year. Simply put, a test year should be representative of the period during which rates will be in effect. As evidenced above in Figure 1, using an average of 2024 rate base is not reflective of 2025. Further, when appropriately compared to an AMA method over the test year (i.e., January 1, 2025 through December 31, 2025), PGE's EOP method at December 31, 2024 does not "inflate rate base" nor does it "reduce regulatory lag." As we demonstrated above in Table 2, PGE has systematically underearned on its rate base compared actual average rate base over the same period. Further, as we describe in PGE Exhibit 1200, Section III, PGE's capital investments over the test period are consistently greater than accumulated depreciation, which results in an increase to actual rate base over the test period, even when using a true AMA method over the test period.

Q. Are the Commission orders AWEC cites relevant or applicable in this case?

A. No. The orders presented by AWEC from the 1970s are not relevant or applicable for multiple reasons. First, these decisions were made in a dramatically different context. Quite simply, a lot has changed in the past 50 years. By way of example, the very nature of what can be included in rate base has changed; at the time, rate base included components such as

[21] AWEC/100, Mullins/11, at 12-15.

construction work in progress and plant held for future use. Today, such costs are excluded from rate base levels, thus lowering the baseline of utilities' cost recovery.

Second, while AWEC cites two non-electric utility decisions for the narrow rate base calculation decision, evaluating electric utility cases from this period reveals a fuller context. AWEC notes that inflation was quite high during the 1970s, similar to current trends, thus old practices from these orders should be followed.[22] However, AWEC neglects to mention that in this same period of the 1970s, with these inflationary pressures, PGE's authorized ROE was between 12.25 and 13.84 percent. Clearly, a fully contextualized assessment of the Commission's approach to revenue requirement calculations suggests that the use of historical AMA was adopted in conjunction with other levers that helped ensure overall adequate recovery. Adopting one disconnected aspect of the Commission's former regulatory approach is not appropriate or reasonable.

Third, the Commission has had a long-standing practice of allowing the use of a forward test year. While AWEC was able to locate certain orders from over 50 years ago that reference the use of historical periods, that is not the commonly accepted Commission practice that has been in place for decades, nor is it aligned with PGE's use of a 2025 Test Year in this case.

Q. What is your overall response to AWEC's AMA proposal and recommendation to the Commission?

A. We recommend the Commission reject AWEC's proposal and method for calculating rate base. AWEC's AMA proposal is a fundamentally flawed approach to calculating PGE's test year rate base, which is based upon false assumptions and premises. AWEC's approach, by averaging plant values over one year prior to the year rate are established, systematically

[22] AWEC/100, Mullins/15.

undervalues the Company's prudently incurred costs to serve customers. A forward-looking test year has been consistently used in Oregon for decades and AWEC's reference to a few Commission orders from over 50 years as support for their proposal is unconvincing.

IV. Cost of Removal

Q. What does AWEC state about PGE's calculation of cost of removal?

A. For the cost of removal, which is the costs of disposal or removing of physical assets, AWEC has incorrectly interpreted how PGE includes these amounts in revenue requirement. AWEC misstates that PGE attributes a portion of depreciation reserves in its depreciation expense calculation to cost of removal reserves. AWEC erroneously claims that because PGE uses net plant balances to calculate depreciation reserve versus gross plant balances that PGE is double counting cost of removal expense because the cost of removal is already embedded in the depreciation rates.[23]

Q. Is PGE correctly accounting for cost of removal expenses in revenue requirement?

A. Yes. While PGE does utilize net plant for the purposes of determining depreciation expense, our calculation of these amounts is consistent with the parameters adopted within PGE's depreciation study (Docket No. UM 2152) through Commission Order No. 21-463. Specifically, PGE's calculations align with Table 2, as provided in Appendix A of the Commission's order.

Q. Explain why AWEC's assertion that PGE is double counting cost of removal expense is incorrect.

A. PGE's depreciation calculation includes two components: 1) a life component in which the book cost of an asset, net of its estimated salvage value, is depreciated; and 2) a cost of removal accrual component. AWEC conflates these two components, inaccurately arguing that cost of removal is embedded within both components and thus double counted. This is not correct. There have been no recent changes to PGE's accounting methodology for depreciation

[23] AWEC/100, Mullins/20.

expense related to cost of removal and the methodology used in this regulatory proceeding matches that which is used to record actual results. PGE's current and historical practice, both in rate proceedings and when recording actuals, is in compliance with U.S. GAAP and FERC accounting requirements. PGE's financial statements are audited annually by Deloitte.

As shown in Table 4, which presents a sample calculation matching the method used for calculating the depreciation expense for each component, cost of removal is appropriately included within the calculation for the cost of removal component and there is no duplication of expense.

Table 4
Example of Depreciation Calculation

Depreciation Calculation - Life Component (inclusive of expected Salvage %)		
Gross Plant Balance (12/2024)	222,153,818	
Gross up for Salvage %	219,932,280	=Gross Plant * (1-Salvage 1%)
Beginning Reserve - Life	88,585,342	
Depreciation Base - Life	131,346,938	=(Gross Plant * (1-Salvage 1%)) - Beginning Reserve Life
Depreciation Expense - Life	482,700	=(Depreciation Base * Depreciation Rate 4.41%)*(1/12)

Depreciation Calculation - COR Component		
Gross Plant Balance (12/2024)	222,153,818	
Gross up for COR %	8,886,153	Gross Plant * (COR 4%)
Beginning Reserve - COR	4,698,853	
Depreciation Base - COR	4,187,300	=(Gross Plant * (COR 4%)) - Beginning Reserve COR
Depreciation Expense - COR	15,388	=(Depreciation Base COR * Depreciation Rate 4.41%)*(1/12)
Total Depreciation Expense (Life + COR)	498,088	

Q. Did Staff review PGE's calculation depreciation and COR?

A. Yes. Staff addresses reviewing PGE's calculation of depreciation, which includes how cost of removal is handled in the calculation. Staff does not make any recommendation to change the method PGE uses to calculate any of the components of depreciation and confirmed that PGE used the OPUC-authorized depreciation rates from UM 2152.[24]

[24] Staff/700, Peng/3-10.

Q. AWEC attempts to support their position by illustrating PGE's growth in depreciation compared to PGE's growth in net plant. Is their comparison accurate?

A. No. AWEC's numbers are neither accurate, nor do they make the proper comparison. A proper comparison of growth would be to compare PGE's gross plant balance with PGE's total depreciation expense. However, a simple review of both PGE's year end regulated net plant balances and gross plant balances, as reported in our results of operations (ROO) reporting from 2019 through 2023 and provided below in Table 5 demonstrates that AWEC's comparison is incorrect.

Table 5
Historical ROO Net Plant and Depreciation (millions)

	2019	2020	2021	2022	2023	% Growth
Year End Gross Plant	10,848.1	10,756.9	11,469.9	11,955.1	12,851.6	18%
Year End Net Plant	5,468.4	5,212.4	6,264.4	6,448.5	6,979.2	28%
Depreciation and Amortization	404.1	429.6	400.8	416.9	454.7	13%

Q. What is your recommendation to the Commission regarding AWEC's COR proposal?

A. AWEC's adjustment for cost of removal is based upon a misunderstanding and mischaracterization of PGE's treatment of COR. PGE treats COR expense consistent with its currently approved depreciation study and this treatment is reviewed annually by our external auditors. AWEC's proposed adjustment and arguments should be rejected by the Commission in full.

V. Investment Tax Credits (ITC)

Q. What was the Parties' response to PGE's proposal for ITCs?

A. None of the Parties support PGE's proposal. Staff does not agree that it is beneficial to provide customers with the value of the ITC as soon as possible because it will result in rate increases later when the benefit goes away. They view this approach as creating intergenerational inequity for the projects. AWEC claims that PGE's proposal to amortize the value of the ITC directly to the customer over a five-year period on a front-loaded declining basis is unfair because PGE is not reducing its rate base, and therefore the return on and of the asset. They also claim the front-loaded declining basis is unfair because it will not accrue as much interest for customers.[25] CUB did not present a specific argument in response to PGE's proposal.

Q. Does PGE want to respond to the statements made by the Parties before discussing the Parties proposed alternatives?

A. Yes. First, PGE disagrees with the manner in which AWEC speaks to the treatment of cash invested in a project. Returning cash as quickly as possible provides upfront reductions to costs recoveries from customers in the near term. Also, returning cash as quickly as possible while it accrues interest on the balance is generally considered a fair proposal within the financing community. Second, CUB's assertion that PGE failed to provide them with accurate analysis is false.

[25] AWEC/100, Mullins/66.

Q. How does PGE respond to CUB's testimony that PGE did not provide accurate analysis on the ITC?

A. CUB requested "all documents, including workpapers or workbooks the company used to *explore* [emphasis added] different ITC amortization options"[26] and PGE provided all analysis, including analysis performed to assess the difference between amortization of the ITC and normalization of the ITC prior to knowing the costs of the Constable and Seaside projects. This analysis was used to determine that opt-out and amortization would be more beneficial than normalization. The analysis was not performed inaccurately; it simply did not match precise Constable or Seaside values because they were unknown at the time the analysis was performed. PGE used this comparative analysis to verify that opting out and amortizing would be better for customers than normalization. Later, when the costs of Constable and Seaside were known PGE performed analysis exploring a number of ways the ITC could be amortized to customers – this analysis was provided to CUB as well through this request.

Q. Did PGE explain this to CUB?

A. Yes, PGE provided explanations similar to the explanation above both via email and over the phone.

Q. Did CUB perform and provide their own analysis, as done by other Parties?

A. No. They only claimed PGE did not perform the types of analysis that they would have wanted to see and determined that PGE's analysis must be inaccurate if the numbers did not match to the Constable and Seaside projects.

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[26] Exhibit 1304, CUB Data Request No. 29.

Q. What have Parties proposed for the treatment of the ITC?

A. Staff proposed that PGE treat the ITC as a reduction to rate base and amortize it over the life of the battery.[27]

AWEC proposes that PGE must opt-out of normalization or take a 30% reduction on the project costs of the Constable and Seaside projects,[28] and they also requested the ITCs be included within the revenue requirement.[29]

CUB did not offer a proposal but stated that they believe there was a case for normalization.[30]

Q. How does PGE respond to the Parties' proposals?

A. While PGE questions whether delaying the return of the value to customers is the best way for customers to realize this value, PGE is open to the proposals by the Parties. PGE's intention was to give customers the most value possible as soon as possible and consistent with the matching principle to offset the increased revenue requirement due to the investment in clean energy in the near-term. A more rapid return of the ITC value to customers also maximizes the net present value of the benefit and is more consistent with the benefits modeled within the RFP. However, if Parties believe that the best value for customers is to return the ITC via a reduced rate base within the revenue requirement, PGE is willing to entertain this proposal.

As such, as an alternative to PGE's initial proposal, and in line with the proposals of Staff and AWEC, PGE would propose to use the actual value of the ITC,[31] less the cost to sell up

[27] Staff/1700, Dlouhy/37 at 1-4.
[28] AWEC/100, Mullins/65-66.
[29] *Id*. 67.
[30] CUB/200, Tran/2-11.
[31] To be determined by a consulting tax expert and based upon IRS regulations.

to 10% of the value, as an offset to PGE's rate base and amortization expense within the revenue requirement with a life that matches the life of the project.

VI. Anderson ITCs

Q. What is the Anderson ITC adjustment suggested by AWEC?

A. AWEC has proposed that that Anderson Readiness Center ITCs be opted out of normalization and subject to a 10-year useful life. The resulting credit would be included in the revenue requirement using deferral methods of accounting and including a reduction to rate base and a reduction to tax expense. Also, they incorrectly propose that PGE should remove any tax assets associated with tax credit carryforwards if PGE could monetize these ITCs through a sale. There are no tax assets associated with Anderson Readiness Center, so there is nothing to remove. Their proposed consequences for not opting out consists of a 30% project cost disallowance to make up for the ITC.

Q. Is PGE willing to opt out of normalization for the Anderson ITCs?

A. Yes, assuming PGE receives commission approval to opt out. However, PGE's options for the Anderson ITCs are limited. As stated in PGE's response to AWEC Data Request No. 123, it is not reasonable to sell the ITCs, as it would be cost prohibitive for customers based on the total value of the ITC. Assuming PGE does opt out of normalization accounting, the Deferral method for accounting for ITCs would apply, but as PGE does not currently have the tax appetite to use this credit, we do not currently support the 10-year distribution that AWEC is suggesting. PGE recommends following its policy of applying the Deferral method of accounting for ITCs, in which the credit is utilized prior to being amortized through income. Additionally, until the credit is utilized, PGE recommends an equal credit and debit to rate base, resulting in zero changes.

Q. What is PGE's recommendation regarding the Anderson ITCs?

A. PGE agrees with AWEC that we can opt out of normalization for this credit and will do so. Since PGE is functionally unable to sell this credit and unable to utilize this credit, for accounting purposes there is currently an equal and offsetting impact to PGE. As such and consistent with the actual impact to PGE's accounting books, PGE proposes to provide this benefit to customers in the future, following PGE's ability to utilize the credit.

VII. Accumulated Deferred Income Taxes

Q. Please describe AWEC's proposed adjustments related to Accumulated Deferred Income Taxes (ADIT).

A. AWEC raises four distinct issues regarding PGE's ADIT balance included in rate base. First AWEC recommends the removal of all Production Tax Credit (PTC) carryforward amounts from PGE's ADIT based on changes to tax law and a PTC utilization estimate using PGE's 2024 budget.[32] Second, AWEC recommends the ADIT associated with PGE's 2020 emergency wildfire and February 2021 storm deferral (major storm deferral) be included in rate base.[33] Third, AWEC recommends removing 50% of PGE's incentive-related ADIT balance.[34] Finally, AWEC argues the ADIT balance associated with Boardman cost of removal be removed from rate base.[35]

Q. Does PGE agree with any of these four proposed AWEC adjustments to ADIT?

A. We agree it is appropriate to remove the Boardman COR ADIT balance. Additionally, we agree, consistent with our incentives request in this case, that it is reasonable to remove 50% of our incentive-related ADIT balance. We do not agree with AWEC's positions on PTC carryforwards or major storm deferral, which are discussed below.

A. PTC Carryforwards

Q. Please summarize AWEC's arguments and proposed adjustment regarding the PTC carryforward ADIT.

A. AWEC makes two primary arguments in support of their proposed adjustment, which removes the entirety of PGE's PTC carryforwards included within ADIT. AWEC argues that as a result

[32] AWEC/100, Mullins/50-51.
[33] *Id.* 53.
[34] *Id.* 54.
[35] *Id.* 51-52.

of the Inflation Reduction Act, PGE has submitted an application to be allowed to sell PTCs on a going forward basis and that information provided as part of that proceeding demonstrates that PGE's carryforward balance will have declined such that it is appropriate to remove the entirety of PGE's PTC carryforward ADIT from rate base.

Q. Do you agree with AWEC's analysis and adjustment?

A. We agree in part. Since the filing of our case, PGE's property sales application to sell 2024 PTCs (Docket No. UP 426) has been approved and PGE has transacted for those PTCs. Thus, as we stated in our opening testimony,[36] we will remove the associated PTC carryforward from our ADIT balance. This represents a reduction of approximately $58.4 million from our 2025 Test Year rate base.

Q. Do you agree with AWEC's recommendation to remove the remaining PTC carryforwards from ADIT?

A. No. While it is PGE's intention to sell generated PTCs on a forward basis, the Inflation Reduction Act does not allow for the sale of PTCs generated prior to 2023, which is what comprises PGE's remaining balance. While AWEC argues that as "carryforward costs are now being considered outside of revenue requirement, it is most appropriate for PTC carryforwards to be removed from base rate revenue requirement,"[37] the fact is only PTCs on a forward-looking basis (i.e., post-2023) are considered outside of PGE's base rates.

Q. What does PGE currently expect its PTC carryforward balance to be as of December 31, 2024?

A. While our initial filing included $58.4 million of 2024 generated PTCs, which we propose removing based on the approval of UP 426, it also included a forecasted utilization amount of

[36] PGE/200, Batzler/Ferchland/28.
[37] AWEC/100, Mullins/51, 1-3.

approximately $25.4 million that we currently do not expect to fully utilize for 2024. Table 6 below compares our initial filed PTC carryforward balance compared to our current expectations.

Table 6
PTC Carryforward Projection (millions)

	As Filed	Current Projection
12/31/23 PTC Carryforward	$74.5	$74.5
2023 PTCs transferred in 2024		($1.5)
2024 PTCs generated, less transferred	$58.4	-
PTCs Utilized	($25.4)	($18.9)
PTC Reduction for Trading Losses	($18.4)	($18.4)
12/31/24 PTC Carryforward	$89.1	$35.7

Q. Based on the above current projection, what does PGE propose?

A. We propose adjusting our filed PTC carryforward downward from a balance of $89.1 million to $35.7 million, which reflects the impact of removing the generated PTCs and updating the PTC utilization amount in our 2024 forecasted balance. In total, this represents a $53.4 million reduction to rate base, which is our most current expectation of this balance at December 31, 2024.

Q. How does the above projection compare to AWEC Exhibit 104, which AWEC uses as the basis of their support?

A. The information relied upon by AWEC for their Exhibit 104 does not reflect any actual 2024 results, which have changed our projected utilization for 2024. By comparison, the basis for PGE's Table 6 above is based upon our recently filed Q2 2024 results and more accurately reflects current expectations. Additionally, AWEC's analysis assumes 2025 utilization, while PGE's rate base and Table 6 is based on December 31, 2024 amounts.

B. Major Storms ADIT

Q. What is AWEC's proposal associated with PGE's 2020 emergency wildfire and 2021 ice storm deferrals?

A. AWEC recommends that PGE include an ADIT benefit within this case associated with these deferred balances, which AWEC calculates as a $26.1 million reduction to rate base using a December 31, 2023 deferral balance. In support, AWEC argues that the timing between deferring these amounts in 2020 and 2021 and the ultimate collection of costs from customers over a seven-year period, results in a favorable deferred tax benefit due to the treatment between book and tax accounting.

Q. Does AWEC's proposal regarding these deferred amounts conflict with their position on other items?

A. Yes. AWEC's position on these deferrals, which have no relation to PGE's revenue requirement in this case, directly conflicts with their position on PTCs, where they indicate that because the cost of PTC carryforwards are now "considered outside of revenue requirement,"[38] they should not be included in the base rate revenue requirement.

Q. Have these deferred amounts ever been considered within base rates?

A. No. These amounts were subject to deferred accounting under ORS 757.259 and have been handled outside of a general rate case proceeding.

Q. Have the proceedings associated with these amounts been ruled upon by the Commission?

A. Yes. Commission Order Nos. 20-389, 22-077 and 22-020 approved the deferrals and Commission Order No. 22-435 adopted a stipulation between PGE, Staff, CUB, and AWEC

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[38] AWEC/100, Mullins/51 at 2.

that resolved all issues related to 2020 and 2021 deferred costs. A stipulation that the Parties agreed would result in rates that are fair, just, and reasonable. The Commission order concurred with this statement indicating that the resolution will result in fair, just, and reasonable rates.

Q. Is AWEC's request similar to the treatment associated with Boardman as they claim?

A. No. As we discuss above, these deferrals have been completely dealt with outside of base rates, the balances are subject to deferred accounting and a final decision on the amortization, including the timing of the collection, was ruled upon pursuant to a stipulation that AWEC signed. In contrast, Boardman was never fully removed from base rates during its life and was not subject to deferred accounting.

Q. Does PGE's position conflict with the position on PTC carryforwards described above?

A. No. Again, there is still a portion of PTCs that are fully handled in base rates and will never be sold, which is what PGE recommends retaining within ADIT and reflecting as of December 31, 2024. In contrast, the PTCs that have been sold pursuant to UP 426 and thus handled outside of base rates, we agree should be removed from the ADIT balance in this proceeding.

Q. What is your recommendation to the Commission regarding the adjustment proposed by AWEC for PGE's Major Storms deferral?

A. We recommend the Commission reject AWEC's proposal. Both the amounts deferred and amortization of amounts has been previously ruled upon by the Commission, resulting in rates that are fair, just, and reasonable and all associated costs and benefits have been wholly dealt with outside of PGE's base rates.

VIII. Oregon Corporate Activity Tax

Q. Please describe AWEC's arguments and proposal to adjust PGE's forecast OCAT.

A. AWEC argues that PGE's method to escalate OCAT resulted in an increase that is much higher than 2023 levels and recommends OCAT be based upon the overall revenue requirement approved.[39] To inform their adjustment, AWEC then develops a calculation, which appears to compare the percentage of revenue subject to the OCAT using PGE's 2022 tax return and PGE's 2023 regulated revenues. This revenue percent is then used as a basis for calculating an adjusted revenue amount, which begins with AWEC's overall revenue requirement proposal. From this AWEC performs a series of calculations that are not fully evident or supported with the material they provided.

Q. How is OCAT calculated?

A. At a very high level, OCAT is calculated on "taxable commercial activity" in excess of $1 million at the rate of 0.57 percent, plus a flat tax of $250 on the taxpayer's first $1 million of taxable commercial activity. Additionally, there is a 35% deduction for cost of goods sold, along with certain amounts excluded from the tax calculation, including franchise fees, public purpose charges, etc.

Q. How has PGE traditionally forecast OCAT amounts?

A. PGE initially recovered the OCAT through deferred accounting, as the tax was unforeseen when initially required and somewhat unpredictable. As this tax has been in effect since 2020, PGE has developed a better understanding and since PGE's 2022 general rate case, has been including a forecast in base rates.

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[39] AWEC/100, Mullins/55-56.

Q. What is PGE's response to AWEC's proposal and adjustment of OCAT?

A. While AWEC did not fully support or explain their method, making it difficult to perform a complete assessment, PGE has a few concerns based on the information provided. First, PGE disagrees with the mixing and matching of 2022 and 2023 amounts. Second, the amount of OCAT for 2023 referenced by AWEC is not the actual amount PGE expects to recognize on its 2023 tax return, which will be filed in September 2024. Finally, PGE disagrees with AWEC's total revenue assumptions used for calculating their OCAT amount.

Q. Has PGE recently reviewed the annual percentage of PGE's total revenue that OCAT represents?

A. Yes. We provide this detail including our current estimate for 2024 OCAT amounts as Confidential PGE Exhibit 1303. The current amount of 2023 OCAT is now expected to be $9.3 million and we now project an OCAT amount of $10.1 million for 2024.

Q. Using recent OCAT amounts, including PGE's current 2024 OCAT expectation, what do you recommend for 2025?

A. We recommend using PGE's current 2024 expected OCAT amount of $10.1 million and escalating it by PGE's current projected January 2025 percentage increase for base business and power costs. This results in a total of approximately $11.1 million and an adjustment of approximately $1.8 million from PGE's initial filing. As an alternative and in line with AWEC's recommendation to base OCAT on the overall revenue requirement approved, PGE recommends using the most recent three-year average of OCAT as a percentage of total revenue (2021-2023) as the basis for determining 2025 OCAT amounts. This average is 0.33% and would be multiplied against PGE's total revenue requirement in this case. Additionally, consistent with other revenue sensitive factors such as OPUC fees and uncollectible revenue, this revenue sensitive factor would be included within the calculation of supplemental schedule amounts for 2025 forward.

IX. Cash Working Capital

Q. What does Staff propose regarding PGE's cash working capital (CWC)?

A. Staff proposes three adjustments for the CWC calculation associated with: (1) revenue lag days, (2) depreciation and amortization, and (3) the inclusion of the adjusted operation and maintenance expenses.[40]

Q. What is CWC or working cash?

A. Working cash is the necessary funds provided by investors on a permanent basis to finance the timing difference between the cash received from billings and the cash paid for operating expenses. To determine the necessary working cash allowance, we use a lead-lag study to measure the average number of days between the following activities:

- Revenue Lag: This measures the number of days between providing services and receiving payment for those services.
- Expense Lag: This measures the number of days between incurring expenses and making the corresponding payments.

We determine the number of days between the activity and the payment (a lag) for each source of revenue and expense and multiply it by the amount of the associated revenue or expense to determine the "dollar days." The dollar days represent a weighted lag for each revenue and expense item. The revenue lag minus the expense lag yields the net "excess lag," which is used to determine the working cash allowance factor.

Q. What working cash allowance factor did you include for this filing?

A. PGE included a 4.222% working cash allowance factor, which was the factor used in UE 416.

[40] Staff/300, Chipanera/9-16.

Q. How did you use the working cash factor allowance in this filing?

A. Similar to prior general rate cases, we applied the working cash factor allowance to PGE's total 2025 operating expenses. The return on the working cash rate base amount compensates PGE for the financing cost of its excess lag.

Q. Do you agree with Staff's adjustment around revenue lag days?

A. No. Revenue lag days are to measure the number of days between providing services and receiving the payment for services. Staff suggests that the revenue lag days calculation be based on days of the month in the year. PGE calculates the revenue lag days based on the cycle meter days, which are a closer alignment to the billing days on customers' bills versus a high-level days of the month calculation.

Q. Is Staff's proposal to remove depreciation and amortization for CWC correct?

A. No. Staff's argument to remove depreciation and amortization from CWC is based on Staff viewing CWC as the product of net lag days and the average daily cost of service, and that PGE does not need a daily cash cushion to cover depreciation and amortization to cover short-term liquidity in the Test Year. However, as we have stated in response to OPUC Data Request No. 438 and reiterate here, the inclusion of depreciation and amortization with the CWC calculation are appropriate as they represent prior cash outlay for the investment made that are not fully compensated until customers repay the depreciation and amortization expense. This approach acknowledges the need to provide compensation for the investments during the lifecycle of the assets.

Q. Can you elaborate?

A. Yes. The full amount of PGE's forecast depreciation and amortization expense (and all prior depreciation and amortization expense to date) is included as a credit to rate base in the form of accumulated depreciation. This deduction from PGE's rate base presumes that recovery of these expenses has occurred. However, that is not correct, as the recovery of PGE's forecast depreciation and amortization will actually occur over the test period. Thus, while the investment that PGE is earning a return on has been imputed by the deduction of test year depreciation and amortization expense, the actual return of these funds occurs over the entirety of the test year.

Q. Does this mean that PGE should be including depreciation and amortization expense within the lead-lag study?

A. Perhaps. However, because PGE no longer includes depreciation and amortization within its lead-lag study, which, all else equal, increased PGE's working cash factor in the past, only including depreciation and amortization expense within the calculation of PGE's working cash compensates PGE for the time value described above.

Q. Are there other reasons to include depreciation and amortization in the calculation of CWC?

A. Yes. Including depreciation and amortization in the calculation of CWC also serves as a proxy for the lag on interest expense payments.

Q. Please explain.

A. PGE must hold working capital in order to service debt expense over the year. However, this lag between incurring annual interest expense and when PGE makes payments is not currently included within PGE's lead-lag study. As such including depreciation and amortization expense in the calculation of PGE's CWC also helps to compensate PGE for the lag between incurring and servicing its interest expense.

Q. Does Staff propose any additional adjustments to CWC?

A. Yes, Staff has included an adjustment to CWC in their revenue requirement calculation for all the adjustments they are proposing for O&M. While PGE does not agree with Staff's adjustments, PGE agrees that CWC needs to factor any updates made to the revenue requirement calculation, which we have done within the revenue requirement provided in PGE Exhibit 1301.

X. Fuel Stock & Materials and Supplies

Q. Please summarize Staff's arguments and adjustments associated with PGE's fuel stock.

A. Staff has separate arguments and adjustments for PGE's natural gas, oil, and CO2 allowances included in rate base, ultimately making five recommendations with four separate adjustments as follows:

1. Staff recommends that an average balance be used to value PGE's natural gas fuel stock, for an adjustment to PGE's rate base of a reduction of $2,121,786.[41]
2. Staff argues that PGE maintains too much natural gas for reliability purposes and recommends PGE conduct an analysis to show the economic value of holding a minimum of $1.2 million dth of natural gas at North Mist.[42]
3. Staff argues that PGE overvaluing its oil stock and recommends value its existing oil stock at current spot oil prices for an adjustment to PGE's rate base of a reduction of $1,592,608.[43]
4. Staff argues that Beaver will lose its oil burning capability in 2025 and recommends a 50% disallowance for an additional reduction of $2,964,020.[44]
5. Staff argues that the entirety of PGE's CO2 allowances should be removed from rate base for an adjustment of $2,108,351.[45]

Additionally, Staff suggests that natural gas should be valued at its purchase price. We discuss PGE's response to Staff's fuel stock testimony below.[46]

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[41] Staff/1400, Dyck/15.
[42] *Id.* 16.
[43] *Id.* 22.
[44] *Id.* 23.
[45] *Id.* 24.
[46] *Id.* 17.

A. Staff's Natural Gas Proposal

Q. Has PGE previously discussed the history of North Mist?

A. Yes. As we described in Docket UE 416, North Mist was part of PGE's Port Westward 2 (PW2) least-cost, least-risk winning bid from PGE's 2012 Request for Proposals (RFP). PGE's 2009 Integrated Resource Plan (IRP) action plan identified the need for approximately 200 MW of flexible capacity to fulfill the dual purpose of meeting load during peak customer demand events as well as providing flexible capacity to follow both load and wind fluctuations.[47] PW2, inclusive of a long-term "no-notice" gas storage contract with Northwest Natural at North Mist provides this need. North Mist was the least-cost fuel supply option as part of the winning RFP bid for flexible capacity needs.

Q. Does PGE agree with Staff's recommendation to value PGE's gas stock at an average price and volume over the year?

A. No. PGE's rate base is established as of December 31, 2024. This is the value of gas that will be in service to customers as of January 1, 2025 and is consistent with how all other rate base amounts are established. Additionally, this is the value of gas that customers will benefit from beginning on January 1, 2025, which aligns with the NVPC benefits provided to customers through PGE's annual update tariff (Docket UE 436). The average 2024 value proposed by Staff neither aligns with the benefits provided to customers in 2025, nor the used and useful amount of gas within PGE's test year.

Q. How does PGE forecast its gas storage volume and price?

A. PGE has modified the way its gas stock is forecast so that it is directly linked to the gas storage amounts included and utilized within PGE's gas storage optimization model included in

[47] *In the Matter of Portland General Electric Company 2009 Integrated Resource Plan,* Docket LC 48, Integrated Resource Plan (November 5, 2009) at 7.

MONET, PGE's NVPC forecast model. That is, both the volume and price are directly from PGE's power cost forecast, which establishes the forecasted use and benefits provided to PGE's customers. PGE is not over forecasting its gas stock as Staff suggests,[48] rather, we are directly linking it to customer benefits.

Q. Staff recommends PGE conduct an economic analysis of gas stock. How do you respond?

A. PGE is not opposed to reviewing the economics associated with gas reserves. However, our gas reserve balance, which has been discussed and modeled within net variable power costs for many years, is not a simple case of economics. This gas is held, both from a forecast and from an operational perspective, for system reliability purposes. The fact is, as we demonstrated in Docket UE 416, the customer benefits provided from North Mist within MONET already far outweigh the customer costs of holding reliability reserves.[49]

Q. Staff states there have been no historical instances in recent years that suggest seven days of gas storage is needed at North Mist. How do you respond?

A. While thankfully not a frequent occurrence we have previously discussed the Westcoast Pipeline rupture on October 9, 2018, which occurred prior to North Mist being operational, as an example. This resulted in nearly all gas imported into the Pacific Northwest at Sumas being cut off, which impacted all natural gas-fueled generating facilities in the region, including PGE's. Directly following this incident, PGE took numerous actions, including:

1. PGE took Port Westward 1 and Port Westward 2 offline to provide relief to pipeline pressures;

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[48] *Id.* 16.

[49] The total benefit provided to customers from PGE's gas optimization model within MONET for 2023 was $11.8 million.

2. Increased real-time market purchases;
3. Returned to service the 518 MW Boardman Coal Plant, which was offline prior to the rupture;
4. Postponed Carty's planned outage to keep it running; and
5. Returned Beaver units that were in a planned outage to service early.

Additionally, PGE strategically utilized Mist storage rights to fuel Port Westward 2 and Beaver during the Forced Majeure issued by regional pipeline operators. Had North Mist been operational, this would have provided additional capability beyond PGE's then current Mist storage rights.

Q. Has gas storage become even more important since this event?

A. Yes. As PGE no longer has Boardman in its fleet and as baseload generators continue to be retired in the West, reliable, no-notice generation has become increasing important to PGE's contingency planning. Simply put, there are no less alternatives to rely upon.

Q. Does the fact that PGE does not have a more recent example validate Staff's concern?

A. No. These are the types of events that no one wants to occur but as a provider of last resort, it is PGE's responsibility to be prepared for the possibility. It would be imprudent not to be prepared. A simple analogy is home insurance. Most homeowners never experience a devastating event to their home. And yet, most homeowners maintain insurance coverage to protect them from the possibility. PGE's fuel reserves serve as this insurance product.

Q. Does PGE agree that it holds different kinds of gas as Staff asserts?

A. No. All of PGE's gas is working gas that is used and useful.

Q. How does PGE respond to Staff's suggestion that natural gas stock should be valued at the purchase price?

A. All of PGE's fuel stock is valued at the purchase price. That is how the weighted average cost (WAC) works, which is how PGE values all fuel stock from a forecast and actual accounting perspective. PGE's forecast of gas stock begins with actual balances that are valued at the actual WAC (i.e., purchase price/units). We also note and will discuss below how this suggestion from Staff directly contradicts their recommendation for PGE's oil stock balances.

Q. What is PGE's recommendation regarding gas fuel stock?

A. PGE recommends that the Commission reject Staff's opportunistic proposals regarding gas fuel stock. PGE customers benefit both financially and operationally from PGE's gas at North Mist and using a year-end balance of this stock directly aligns with the benefits provided to customers, the overall rate setting method of PGE's rate base, and is consistent with the used and useful standard.

B. Staff's Oil Proposal

Q. Staff argues that PGE overvalues its oil stock and that it should be valued at current 2023-2024 forecasted oil prices.[50] Does PGE agree?

A. No. While PGE does compare existing balances to lower of cost or market (LCM), unless that indicates that PGE's WAC valuation is materially above a current market value, WAC is how PGE values its oil.

Q. Has PGE recently performed an LCM comparison to its current WAC?

A. Yes. PGE recently compared its oil WAC to NYMEX heating oil futures contracts, which are actively traded on commodity exchanges such as the Chicago Mercantile Exchange and are

[50] Staff/1400, Dyck/21.

what PGE uses to value heating oil. These prices show a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** January 2024 heating oil market price, with a trade date of December 29, 2023 that is higher than PGE's actual WAC of $2.49 at the end of 2023, which is what PGE used for establishing its December 31, 2024 year-end balance. Simply put, PGE is not "overvaluing" oil stock, as the value is the actual cost and this cost is below market.

Q. Does PGE have additional concerns with Staff's argument that PGE's oil stock is "overvalued"?

A. Yes. Staff's proposal here is in direct conflict with their suggestion that PGE value gas at its actual purchase price. PGE uses the WAC method for valuing all fuel and WAC is the standard method for valuing fuel. PGE's WAC calculation accounts for the price paid and price sold for every molecule of PGE fuel. Further, GAAP requires consistency of inventory costing, and a company is required to use the same cost formula for all inventories having a similar nature and use, which is what PGE does.

Q. Is PGE phasing out oil use at Beaver in 2025?

A. No. As we stated in our response to OPUC Data Request No. 507, oil at Beaver will be phased out in 2026. All of PGE's oil at Beaver is currently and will continue to be used and useful through the entirety of 2024 and 2025. Staff points to language within the Beaver Modernization Project justification form to support their assertion of a 2025 date.[51] However, this information was from 2021 and is clearly no longer accurate. It is unclear why Staff neglects to recognize this.

[51] Staff/1400, Dyck/22-23.

Q. What will happen to the Beaver oil after being phased out in 2026?

A. Two options are currently being explored. The first is to generate electricity with the oil. The second is to sell the oil. While a final decision has yet to be made, PGE currently considers selling the oil as the most cost-effective and prudent method of removing the oil from Beaver's site.

Q. What is PGE's recommendation regarding oil stock?

A. PGE recommends that the Commission reject Staff's proposals regarding oil stock. Oil is currently and will continue to be used and useful during the test year of this rate case. Additionally, PGE's valuation of this fuel at WAC is consistent with industry standards and consistent with the method Staff suggests for valuing gas.

C. Staff's CO2 Allowance Proposal

Q. How does PGE respond to Staff's proposal regarding CO2 Allowances?

A. PGE disagrees with Staff's arguments. PGE's CO2 allowances are used and useful as they are used to comply with PGE's carbon obligations associated with power sales that benefit customers through PGE's NVPC forecast. PGE has kept a stock of these allowances to maintain some flexibility in the timing of its allowance procurement and the WAC of these allowances is significantly lower than current market prices.

Q. What is PGE's recommendation regarding CO2 allowances fuel stock?

A. While PGE disagrees with Staff's arguments for removing this balance, we currently expect to utilize a considerable portion of our remaining balance of these allowances prior to December 31, 2024. As such, consistent with PGE's method of determining rate base in case as of December 31, 2024, we have removed the entirety of this balance (i.e., $2,108,351) from the updated revenue requirement provided in PGE Exhibit 1301.

D. Materials and Supplies

Q. What is Staff's proposal regarding materials and supplies?

A. Staff argues that PGE should be using a three-year historical average of monthly materials and supplies balances and arrive at a total by escalating that average to 2024 using All-Urban CPI. Staff asserts that this method will be more accurate, and that PGE has over forecast its materials and supplies amounts.

Q. Are there any issues with Staff's analysis?

A. Yes. There are issues with escalation, and some of the math. Regarding escalation, Staff Exhibit 300 clearly states that it is Staff's methodology to use the "All-Urban CPI forecast" from the Oregon Office of Economic Analysis, and specifically it's June 2024 publication.[52] Confusingly, this is not the escalation consistently used in Staff Exhibit 1500. The escalation suggested in Staff Exhibit 300 would be 3.3% for 2024 and the escalation used in the workpaper for Staff Exhibit 1500 is 2.7%.[53]

In addition, there are also issues with how numbers are reported and escalated. The Staff Exhibit 1500 workpaper escalated historical materials and supplies balances up through 2023, when actually they should be escalated through 2025. In addition, Staff seems to have over-reported the 2024 March forecast by $800 thousand in its analysis (it should be $78,006,000 as reported in PGE's response to Standard Data Request No. 084-A, instead of $78,806,000).

[52] Staff/300, Chipanera/18, lines 5-9.
[53] https://www.oregon.gov/das/oea/Documents/OEA-Forecast-0624.pdf, page 45.

Q. Is Staff correct that PGE has "overestimated the non-fuel materials and supplies balance?"[54]

A. No. In fact, PGE's actual June 2024 ending balance is now higher than the forecasted December 2024 ending balance that PGE included in rate base for the 2025 test year. PGE's June 2024 ending balance is approximately $84.6 million, while the amount reported in SDR 084-A, which is what is included in PGE's test year rate base is only $78.5 million.[55]

Q. What is the primary driver of PGE's materials and supplies balance?

A. The largest source of PGE's materials and supplies balance is transmission and distribution (T&D) materials.[56] As PGE's T&D system continues to grow and become increasingly complex the materials and supplies PGE must keep on hand to immediately respond to impacts on PGE's T&D system must also expand. These materials include poles, wires, transformers, tools, and numerous other pieces of equipment necessary for PGE's line crews to perform their duties effectively and efficiently. Coupled with this growth is the fact that the cost of these materials has also significantly risen in recent years. For example, using Federal Reserve Bank of St. Louis Economic Data (FRED) PGE calculated an annual inflation rate for wood poles from July 2021 to June of 2024 of 13.8%. This high inflation is similar for transformers with PGE using FRED to calculate an annualized inflation rate on transformers of 13.4% over the same period.

Q. What is PGE's recommendation on this issue?

A. It is PGE's recommendation that the Commission reject Staff's proposed three-year historical average approach and find that the amounts included in PGE's case are prudent. Materials and

[54] Staff/1500, Moore/3 lines 5-6.
[55] See PGE Exhibit 1305.
[56] T&D related materials and supplies have comprised between 70% to 78% of PGE's total materials and supplies balances over the last two years.

supplies for PGE's T&D operations have grown as PGE's system has grown and the cost of these supplies has been subject to extreme levels of inflation over the last three years, which is significantly outpacing core inflation amounts. Additionally, PGE's current actual balance for materials and supplies is greater than amounts forecast in the test year.

XI. Other Revenue – Joint Pole and Steam Revenue

Q. What are the adjustments to Other Revenue that Staff proposes?

A. Staff proposes to adjust PGE's Joint Pole and Steam revenue using a three-year average from 2021 through 2023. This results in an approximate $0.7 million increase to joint pole revenue and a $1.6 million increase to PGE's steam sales revenue.[57]

Q. Do you agree with Staff's proposal to base the test year forecast on a three-year average for joint pole and steam sales revenue?

A. No. It is more appropriate to base these forecasted revenues on expectations of revenue informed by customer information. Actual joint pole and steam sales revenue can be unpredictable and variable for differing reasons. For joint pole revenue, while the rates charged and number of attachments can be somewhat consistent, certain revenues such as sanctions revenue and wireless colocation revenue for example can be difficult to predict. Steam sales revenue is entirely dependent on forecasted expectations provided from the third-party food production facilities who purchase the steam. Simply relying on actuals to inform a forecast can be misleading when anomalous years are included in the period reviewed, as is the case in the data Staff uses for both joint pole and steam sales revenue.

Q. Please explain.

A. The data relied upon from Staff includes outlier years for both joint pole and steam sales revenue that are skewing the results and leading to an average that is not indicative of a normal level of these revenues. Specifically, the 2023 revenues for joint pole and 2022 revenues for steam sales were atypical from adjacent years and should not be included within an averaging of results.

[57] Staff/2000, Abraham/3-5.

Q. Why do you consider these years outliers?

A, Not only were the amounts materially different from adjacent years, there are specific reasons behind the abnormal increases. Steam sales revenue for 2022 was greater than normal due to a steam customer, who suffered a mechanical failure to their on-site boiler in 2022. Due to this failure, the customer used a greater than normal amount of steam from PGE until their onsite boiler was returned to service in the later part of 2022. Joint pole revenue for 2023 was greater than normal due to greater than expected sanctions from pole occupant non-compliance. While PGE budgets for a level of sanctions revenue within the 2025 joint pole revenue forecast, it is not reasonable to expect the level from 2023 to be repeated.

Q. How does an average removing these anomalous years compare to PGE's test year forecast?

A. As shown in Table 7 below, when replacing both 2023 joint pole revenue and 2022 steam sales revenue with 2020 actuals, the normalized average is consistent with PGE's test year forecast.

Table 7
2020-2023 Joint Pole and Steam Revenues

	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	Normalized Average	2025 Forecast
Joint Pole	(12.4)	(14.2)	(14.3)	~~(17.5)~~	(13.6)	(14.6)
Steam Sales	(1.4)	(2.6)	~~(5.1)~~	(4.4)	(2.8)	(2.3)
Total					**(16.4)**	**(16.9)**

Q. What is PGE's recommendation for the test year forecast of joint pole and steam sales revenues?

A. PGE recommends the Commission reject Staff's proposed adjustment to these other revenue amounts. PGE relies upon information from third parties to inform a reasonable forecast of expected revenue and not historical averages. Furthermore, when replacing anomalous years with 2020 actuals PGE's three-year average revenues are consistent with the 2025 test year forecast.

XII. PGE Grants

Q. Please summarize Staff's proposal to disallow $700,000 in O&M costs relating to PGE's federal grant funding.

A. Staff is recommending the removal of $600,000 in expense that PGE included in the test year for this rate case relating to its federal Grid Edge Computing Grant (Grid Edge),[58] plus a reduction to O&M of $100,000 to reflect 10 percent of the 2025 base for the four federal grants PGE has received thus far. Staff's belief is that these expenses may be federally reimbursable and thus should not be charged to customers.[59]

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

A. Staff notes that they are still working through their analysis and offer their proposal as "a starting point" with no fact-based argument or evidence to support this position.[60] It is true that PGE is eligible for reimbursement of indirect costs under the 10 percent de minimis rate, which is known as the Modified Total Indirect Cost and is a subset of total project costs, and that such reimbursements will benefit customers by reducing PGE's O&M costs. However, as Staff acknowledges, PGE will also incur non-reimbursable O&M in support of the grants (e.g., cost share) that were not included in the 2025 revenue requirement as they were not yet estimable at the time of our filing. If Staff recommends an adjustment for the indirect 10 percent reimbursement for the future grants, then we must also consider estimates for non-reimbursable O&M expected to be incurred in 2025 for the future grants that are in current negotiations.

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[58] Referred to in Staff's testimony as the Smart Grid Chip Grant.
[59] Staff/1100, Peterson/21-23.
[60] *Id.* 23.

Q. What non-reimbursable O&M costs does PGE expect to incur in 2025?

A. Due to the timing of the rate case and the timing of budget negotiations on the grants, these amounts were not yet known or knowable at time we filed UE 435 and remain uncertain. However, based on progress to-date in negotiations for the larger grants (e.g., Hydrogen Hub, Grid Edge Computing, and Confederated Tribes of the Warm Springs), PGE currently expects it will incur approximately $4 million in net non-reimbursable O&M cost share in support of the grants in 2025. This amount is net of the estimated 10 percent indirect rate reimbursement.

Q. Given PGE's estimated non-reimbursable costs, is Staff's proposed reduction reasonable?

A. No. In Staff Exhibit 1100, Staff recommends a reduction of $700,000 ($600,000 for Grid Edge Computing and $100,000 for indirect cost credit). In fact, based on current estimates for 2025 non-reimbursable O&M cost share related to these grants, the revenue requirement should instead be incrementally increased by approximately $3 million. The current request in the GRC is not adequate to cover our expected cost of service on behalf of customers in 2025 related to the grants, and therefore a reduction of $700,000 is not warranted.

XIII. Capital Attestations

Q. Please summarize AWEC's proposal regarding an attestation process for PGE's capital investments.

A. AWEC proposes an attestation process for all PGE capital projects in which the final costs of the projects are documented with potential rate adjustments if the costs for any given project is less than the prudently determined amount. AWEC's attestation process would require an officer of PGE to file a project-by-project specific attestation for all forecast projects included in the final, approved rate base with a capital budget exceeding $1,000,000. Further, those projects with a capital budget of less than $1,000,000 would be subject to an attestation on an aggregate basis.

The attestations would be required in two filings, one 15 days before the rate effective date, and the second, 45 days after the rate effective date. The first filing (provisional) would incorporate all plant additions up to that date and, based on the best information available to PGE at that time, evaluate the actual capital expected to be placed into service as of the January 1, 2025, rate effective date. The second attestation (final) would explain any variances between its provisional capital attestation filing and the actual plant placed into service. If any project included in the capital forecast is not in service or has a capital cost less than PGE had forecast, PGE would be required to reduce the ultimate rates approved in the Commission's final order.

Q. Why does AWEC feel an attestation process is necessary in this docket?

A. AWEC claims such an attestation process has been used by the Commission in the past and continues to be necessary to ensure that rates only include capital that is prudent and used and useful for the benefit of ratepayers.

Q. Do you agree with AWEC's justification for the need of an attestation process?

A. No. PGE proactively controls project costs where it can and works diligently to minimize impacts to customers and ensure projects are placed into service timely. Even without an attestation process, PGE's rates will reflect capital put into service and deemed used and useful for the benefit of ratepayers. Also, the evidentiary phase of this proceeding allows for an assessment by the Commission of the prudence of requested capital investments, with or without an attestation process. The Commission has acknowledged that in rate case proceedings, the Commission sets a utility's rates to approximate the costs and investments that will likely be incurred in the period of time that rates will be in effect.[61]

Q. Do you agree with AWEC's implied position that any actual project costs higher than initially estimated for the project is inherently imprudent?[62]

A. No. As proposed, AWEC's one-sided attestation process, assumes that any actual over-budget project cost must automatically be removed from recovery and could never be deemed prudent. This argument assumes the ability to perfectly predict the future and is counter to what AWEC themselves quoted from the Vansycle Ridge Project:

> Prudence is determined by the reasonableness of the actions "based on information that was available (or could reasonable have been available) at the time."[63]

Q. Has AWEC deemed any particular project in this rate case filing to be imprudent?

A. No. While PGE is uncertain about the extent to which AWEC has reviewed the 2,000+ pages of discovery responses provided by PGE regarding the capital projects included in this case, AWEC's position seems to suggest a presumption of imprudence solely based on instances

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[61] "The test year should be representative of the period during which the rates will be in effect." Portland General Electric, UF 3339, Order 77-776, p. 7.

[62] AWEC/100, Mullins/26 at 18-19.

[63] *See In the Matter of the Application of Portland General Electric Company for Approval of the Customer Choice Plan*, Docket No. UE 102, Order 99-033 (Jan 27, 1999).

where a project's final cost deviates from its initial cost estimate, without further examination of the underlying reasons for such variances.

Q. Is PGE opposed to the use of any attestation processes in this docket?

A. While PGE does not agree with the necessity of an attestation process, PGE is amenable to discussing a fair and balanced attestation process for a subset of its capital additions in this docket.

Q. What would PGE propose as a fair and balanced approach to a possible attestation process for capital projects in this docket?

A. PGE proposes that a fair and balanced attestation approach would include projects placed in-service projected to be in-service between October 1 and December 31, with project budgets of $5 million or greater based on the May 1, 2024 capital update filing. To avoid customer confusion resulting from multiple rate filings and ultimate bill changes, we recommend a one-time attestation filing, 45 days after the rate effective date, which would allow for finalized transfers to plant accounting while still being timely for customers.

PGE further stipulates that any fair and balanced attestation process would reflect a neutral over/under budget to actual cost position, particularly given Parties ability to review the actions PGE had taken on projects throughout this proceeding. As stated, PGE makes every effort to stay as close as possible to budget during execution of these projects. A one-sided attestation process would run counter to the balanced regulatory compact equation assumed by those who are funding these projects.

Q. Can you summarize the provisions of a capital attestation process that PGE feels would be a fair and balanced approach in this docket?

A. Yes. While not agreeing to the necessity of a capital attestation process, PGE could consider a process that contained the following elements as being fair and balanced for all rate case stakeholders:

- Include capital projects and amounts included in PGE's May 2024 rate case filing update and reviewed in the evidentiary process.
- Only include projects placed in service between October 1 and December 31, 2024.
- Include a $5 million forecast project cost threshold on a project-by-project basis for inclusion in the process.
- Include a one-time attestation filing and rate adjustment 45 days after the rate effective date.

Be variance neutral and include both over and under budget amounts in the attestation process and rate calculation.

XIV. Qualifications

Q. Stephanie Meeks, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting from National American University in 2002. I joined PGE in April 2024, working as a Regulatory Consultant in the Rates and Regulatory Affairs. I have worked at a combination of electric and gas utilities since 2006 in various positions including Revenue Requirements Senior Analyst, Utility Gross Margin Manager, and Regulatory Manager.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1301	Updated Revenue Requirement
1302	UE 416 Testimony on Rate Base Mismatch
1303C	2020-2025 OCAT Detail
1304	PGE's response to CUB Data Request No. 029
1305	6/31/2024 Materials and Supplies Balance

Portland General Electric Company
2025 Revenue Requirement Summary
Inclusive of Constable BESS
($000)

	UE 435 Base Revenue			Percent
	Total Increase:	190,528		6.88%
	Base Business 2024	Constable Jan. 1, 2025	UE 416 Adjustment	Total Results
	(1)	(2)	(3)	(4)
1 Sales to Consumers	2,978,702	10,307	(4,463)	2,984,546
2 Sales for Resale	-			-
3 Other Revenues	46,271			46,271
4 Total Operating Revenues	3,024,974	10,307		3,030,818
5 Net Variable Power Costs	977,858	(8,038)		969,820
6 Production O&M (excludes Trojan)	147,492	633		148,125
7 Trojan O&M	64			64
8 Transmission O&M	22,099	350		22,449
9 Distribution O&M	209,199			209,199
10 Customer & MBC O&M	90,916			90,916
11 Uncollectibles Expense	11,915	41		11,956
12 OPUC Fees	15,069	52		15,121
13 A&G, Ins/Bene., & Gen. Plant	207,260	74		207,334
14 Total Operating & Maintenance	1,681,871	(6,887)		1,674,984
15 Depreciation	389,083	8,329		397,412
16 Amortization	89,722	-		89,722
17 Property Tax	102,796	2,353		105,149
18 Payroll Tax	23,909			23,909
19 Other Taxes	14,249			14,249
20 Franchise Fees	76,407	264		76,671
21 Utility Income Tax	124,379	126		124,505
22 Total Operating Expenses & Taxes	2,502,416	4,185		2,506,602
23 **Utility Operating Income**	522,558	6,121		524,216
24 **Rate Base**				
25 Gross Plant	13,676,970	154,192		13,831,162
26 Accum. Deprec. / Amort	(5,783,036)	(8,329)		(5,791,365)
27 Accum. Def Tax	(778,162)	(18,739)		(796,901)
28 Accum. Def ITC	-			-
29 **Net Utility Plant**	7,115,772	127,124		7,242,896

6.3%	<-- Base Rate Portion of Total Price Change
$ 3,025,131	

	Base Business 2024	Constable Jan. 1, 2025	UE 416 Adjustment	Total Results
	(1)	(2)	(3)	(4)
30 Misc. Deferred Debits	29,255			29,255
31 Operating Materials & Fuel	101,675			101,675
32 Misc. Deferred Credits	(39,249)	(41,632)		(80,881)
33 Working Cash	105,650	177		105,827
34 **Rate Base**	7,313,103	85,669		7,398,771
35 **Rate of Return**	7.146%			7.146%
36 **Implied Return on Equity**	9.650%			9.650%

	Base Business 2024 (1)	Constable Jan. 1, 2025 (2)	UE 416 Adjustment (3)	Total Results (4)
37 Effective Cost of Debt	4.641%	4.641%		4.641%
38 Effective Cost of Preferred	0.000%	0.000%		0.000%
39 Debt Share of Cap Structure	50.000%	50.000%		50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%		0.000%
41 Weighted Cost of Debt	2.321%	2.321%		2.321%
42 Weighted Cost of Preferred	0.000%	0.000%		0.000%
43 Equity Share of Cap Structure	50.000%	50.000%		50.000%
44 State Tax Rate	7.445%	7.445%		7.445%
45 Federal Tax Rate	21.000%	21.000%		21.000%
46 Composite Tax Rate	26.882%	26.882%		26.882%
47 Bad Debt Rate	0.400%	0.400%		0.400%
48 Franchise Fee Rate	2.565%	2.565%		2.565%
49 Working Cash Factor	4.222%	4.222%		4.222%
50 Gross-Up Factor	1.368	1.368		1.368
51 ROE Target	9.650%	9.650%		9.650%
52 Grossed-Up COC	8.919%	8.919%		8.919%
53 OPUC Fee Rate	0.5059%	0.506%		0.506%
Utility Income Taxes				
54 Book Revenues	3,024,974	10,307		3,035,281
55 Book Expenses	2,378,038	4,059		2,382,097
56 Interest Deduction	169,701	1,988		171,688
57 Blank	-			-
58 Permanent Ms	(14,546)	(3,954)		(18,499)
59 Deferred Ms	161,013	(20,693)		140,320
60 Taxable Income	330,769	28,907		359,676
61 Current State Tax	24,626	2,152		26,778
62 State Tax Credits	(10)			(10)
63 Net State Taxes	24,616	2,152		26,768
64 Federal Taxable Income	306,153	26,755		332,908
65 Current Federal Tax	64,292	5,619		69,911
66 Federal Tax Credits	-			-
67 Excess ADIT Reversal (ARAM)	(7,812)			(7,812)
68 ITC Amort		(2,082)		
69 Deferred Taxes	43,283	(5,563)		37,720
70 Total Income Tax Expense	124,379	126		126,587
71 Regulated Net Income	352,857			352,528

	Base Business 2024	Constable Jan. 1, 2025	UE 416 Adjustment	Total Results
	(1)	(2)	(3)	(4)
72 Check Regulated NI				356,991

III. Average Rate Base

Q. What is Staff's argument and recommendation regarding PGE's method for determining rate base?

A. Staff argues that PGE should not determine rate base using year-end point in time values but instead should use a method they propose and incorrectly term the "average of monthly averages" method. As support for this proposal Staff states this as the method "most commonly used by the Commission." As support for their conclusion, Staff references a series of Commission orders,[10] which all predate the promulgation of Oregon's used and useful standard, codified in 1979.

Q. Is Staff's proposal a method that has ever been used by the Commission or any regulated utility in Oregon?

A. No. Contrary to their claim, based on PGE's research, what Staff is proposing has never been used by any utility in the state of Oregon and is unlikely to have been used by any other state commission.

Q. What is the "method" Staff is proposing?

A. Staff's method is <u>not</u> what is commonly referred to as the "average of averages" method. Rather, Staff's method mixes and matches year-end numbers with average numbers, resulting in a very inequitable and unbalanced view of PGE's rate base, which has no historical precedent nor reasonable logic behind it.

Q. Please explain.

A. Staff's method uses PGE's filed year-end (i.e., 12/31/2023) amount for gross plant and then effectively adds another half year of accumulated depreciation using PGE's total filed

[10] Staff/800, Stevens-Young/4-5, referencing Commission Order Nos. 70-797, 74-898, 76-061, and 76-954.

depreciation expense, which they state is an approximation of average accumulated reserve over the test period (i.e., 1/1/2024 through 12/31/2024).

Q. What is the method PGE used prior to its 2015 test year general rate case?

A. PGE's average of averages method used prior to 2015 took the average of monthly average balances of the test year for all rate base components, including gross plant, accumulated depreciation, accumulated deferred income taxes, materials and supplies, and deferred credits and debits. For this rate case, that would have equated to the average of average monthly beginning and ending balances from January 1, 2024 through December 31, 2024. Using this method, which was historically used by PGE and other Oregon utilities, correctly reflects each component of rate base over the same period of time. PGE's current method also correctly reflects each rate base component at the same point in time. Alternatively, Staff's method, which again PGE can find no history or precedent of ever being used, opportunistically mixes time periods between gross plant and net plant amounts.

Q. What is the history behind using the average of averages method that PGE describes above?

A. Based on a review of Commission Orders, PGE began using the average of averages method we describe above not long after Oregon Ballot Measure 9 was approved by voters in November 1978.[11] In fact, PGE filed a general rate case in April of 1978, which the Commission ruled upon on January 25, 1979, just following the passage of Measure 9. Commission Order No. 79-055 states the following (in part), regarding PGE's test year:

> The language of the ballot measure excludes from rate base assets which are not presently "in service." Presently means, firstly, "in a short time" and, secondly, "at this time" according to the American Heritage Dictionary, 1973. Thus it is obvious that a distant test period would be prohibited by the

[11] *See* https://ballotpedia.org/Oregon_Limitations_on_Public_Utility_Rate_Base,_Measure_9_(1978)

> ballot measure. A near future test period is clearly allowed by the terms of the measure.
>
> The voters intended that rates be set based on assets either now or shortly "in service." This implies an accurate matching of revenues, expenses, and return on utility assets. Since the most accurate matching of revenues, expenses, and earnings base for the period that the new rates are to be effective can be provided by a near future test period in this case, its use is consistent with the ballot measure.
>
> The rates authorized will not go into effect before January, 1979; therefore, 1979 is representative of the period during which the rates will be in effect.
>
> The decision of the Administrative Law Judge is affirmed. The year 1979 is, therefore, adopted as the test period for this proceeding.[12]

Q. Was Measure 9 codified into law?

A. Yes. Measure 9 was codified into what is now ORS 757.355.

Q. Does ORS 757.355 still use the term "presently"?

A. Yes. So, if following Staff's logic of relying on Commission Orders from over forty years ago for support and justification, Commission Order No. 79-055 was issued after every order Staff cites and after Ballot Measure 9 and it clearly would allow for PGE to use average plant closings over the test period.

Q. What method did PGE use for establishing rate base prior to Commission Order No. 79-055?

A. Prior to Order 79-055 and prior to the enactment of ORS 757.355, a variety of different methods were proposed and adopted. In Commission Order No. 70-797 cited by Staff, the "end-of-the-year" method PGE proposed, was actually just a different type of averaging using beginning and ending year balances over the test year versus the monthly average of test year rate base.[13] Commission Order Nos. 75-832 and 76-601 approved what was called the Total

[12] *In the Matter of Revised Tariff Schedules applicable to electric service in the State of Oregon, filed by Portland General Electric Company*, Docket UF 3443, Order No. 79-055 (Jan. 25, 1979) 9.

[13] *In the Matter of the suspension of revised tariff schedules applicable to electric service in the State of Oregon by Portland General Electric Company*, Docket UF 2811, Order No. 70-797 (Dec. 11, 1970) 9.

Capital Investment (TCI) earnings base approach, which included construction work in progress and other future capital expenditures in rate base used for setting prices.[14] Commission Order No. 76-601 states the following:

> In the last PGE rate proceeding, Order No. 75-832 (Sept. 26, 1975), the Commissioner determined that a total capital investment earnings base (TCI) more adequately reflected PGE's actual investment, provided higher quality of earnings capacity and thereby made it easier and less costly to attract additional invested capital. The Commissioner adopted a TCI earnings base for PGE.[15]

Q. Why reference these historical orders if they all predate ORS 757.355?

A. The purpose of referencing these orders is to illustrate that a variety of methods have been previously authorized; however, none that predate ORS 757.355 are relevant. In fact, no order that Staff references is relevant to their argument, as they all predate ORS 757.355. The only relevant order cited thus far is Order No. 79-055, which allowed PGE to use an average of test year averages for rate base assets. However, as we describe above, this is <u>not</u> what Staff is proposing.

Q. Is PGE's current year-end method consistent with ORS 757.355?

A. Yes. PGE's current rate base method establishes all rate base items just prior to PGE's proposed price effective date, which clearly meets the used and useful standard.

Q. Do other utilities use a year end method?

A. Yes. In their most recent general rate case, Docket No. UE 399, which was filed using a 2023 test year, PacifiCorp states the following in their opening testimony: "The Company's rate base in this proceeding is established using year-end 2022 balances for plant-related rate

[14] *In the Matter of revised tariff schedules applicable to electric service in the State of Oregon, filed by Portland General Electric Company*, Docket UF 3157, Order No. 75-832 (Sept. 26, 1975) 12-18; *In the Matter of revised tariff schedules applicable to electric service in the State of Oregon, filed by Portland General Electric Company,* Docket UF 3218, Order No. 76-601 (Sept. 1, 1976) at 9-10.

[15] UF 3218, Order No. 76-601 at 9.

base…"[16] In fact, based on our research of publicly filed testimony, PacifiCorp has used the year-end method for plant-related rate base since 2013,[17] which was prior to PGE's change in UE 283. While we found other examples of investor-owned utilities using average rate base over the test year similar to what PGE calculated prior to UE 283, we have found no examples of any utility in Oregon or elsewhere using the approach Staff has suggested.

Q. Did Staff write testimony in UE 399 or in any prior rate case opposing PacifiCorp's use of year-end rate base for plant-related items?

A. No.

Q. As support for their unbalanced proposal Staff states that under PGE's current method "the customer rates will be calculated assuming this new plant is not reduced due to depreciation at all throughout the Test Year."[18] Is this statement accurate?

A. It is not. In fact, for any new plant placed into service over the year prior to PGE's test year (i.e., January 1, 2023 through December 31, 2023), PGE annualizes a depreciation amount and includes that within its December 31, 2023 accumulated depreciation balance in rate base. In other words, an asset with an in-service date of December 31, 2023 still receives a full year's worth of depreciation and corresponding accumulated depreciation as a reduction to rate base. Thus, contrary to one of Staff's key arguments, PGE's depreciation expense basis is aligned with its accumulated depreciation basis included in rate base. Rather than reflecting "actual depreciation during the Test Year,"[19] Staff's method serves to double count the impact of accumulated depreciation for assets placed into service during 2023.

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[16] *In the Matter of PacificCorp Request for General Rate Revision*, Docket UE 399, PAC/300, Bulkley/55 at 19-20 (Mar. 1, 2022).
[17] See *In the Matter of PacifiCorp's Request for General Rate Revision*, Docket UE 246, PAC/100, Reiten/8 and PAC/1100 (Mar. 1, 2012).
[18] Staff/800, Stevens-Young /3.
[19] *Id*. 4.

Q. Beyond the fact that Staff's proposal is unbalanced, opportunistic, and not based on any prior Commission practice or precedent, are there other impediments to employing Staff's method?

A. Yes. Staff's proposal would violate tax normalization rules as defined in Internal Revenue Code, Section 168(i)(9). As we discuss in PGE Exhibit 200, normalization rules require consistency in the calculation of book depreciation expense, tax expense, accumulated book depreciation, and accumulated deferred income taxes.

Q. What is the potential result of PGE being found in violation of normalization rules?

A. Internal Revenue Code Section 168(f)(2) states that if a utility does not use a normalization method of accounting, the utility may not take advantage of the benefits of accelerated tax depreciation provided in Section 168. PGE would be required to utilize book depreciation to calculate its income tax expense. This would adversely impact customer prices. Without the ability to claim accelerated depreciation benefits, PGE and customers would see higher borrowing costs and, all else equal, PGE's regulated rate base would be higher, as customers would no longer be afforded the ADIT benefits associated with accelerated depreciation.

Q. Does the statement that Staff just now noticed how PGE calculates rate base in GRCs seem reasonable or relevant?

A. No. While not particularly relevant, PGE finds this statement to be a red herring argument. Since PGE's 2015 test year general rate case (UE 283) and prior to the current proceeding, there have been four additional general rate cases (i.e., Docket Nos. UE 294, UE 319, UE 335, and UE 394), in which PGE has included a description of how rate base is established (i.e., rate base balances as of December 31 of the year prior to PGE's test year). For all six of these cases (UE 283 through UE 416), PGE has clearly stated in multiple sections of its revenue requirement testimony the use of rate base balances at year-end being the method for establishing rate base.

Q. Did Staff recognize PGE's use of year-end rate base in UE 283?

A. Yes. Staff Exhibit 600 in UE 283 clearly recognized this change:

"PGE has proposed a normalized future test period of calendar year 2015, except that for rate base they use the forecast balance as of December 31, 2014." [20] Staff continues in the same section of testimony to then indicate that they find PGE's method "reasonable."[21]

Q. Is PGE the only utility using this method?

A. No. As we state above, PacifiCorp has clearly been using the year-end method for all plant-related items, including accumulated depreciation and ADIT, since their 2013 test-year GRC. Based on the fact that the two largest utilities in the state have been employing this method for approximately ten years in their general rate case filings and that Staff clearly recognized this change in method when PGE employed it and found it to be reasonable, we find Staff's claim of not noticing this change until now to be unconvincing and contradictory to their own prior testimony and findings.

Q. Why did PGE adjust its method for setting test year rate base in UE 283?

A. Prior to UE 283, PGE used average of averages for all rate base components, which had been PGE's standard practice since Commission Order No. 79-055, where the Commission interpreted "presently" as allowing for the inclusion of "assets either now or *shortly* [emphasis added] 'in service.'" In general rate cases prior to UE 283, Commission Staff increasingly argued against the notion of using average rate base over the test period. While PGE disagreed

[20] *In the Matter of Portland General Electric Request for General Rate Revision*, Docket UE 283, Staff/600, Garcia/1 at 13-16 (Jun. 11, 2014).
[21] *Id*. 2 at 5-7.

with Staff's arguments on the issue and no Commission Order ruled that PGE could not use average rate base over the test year, PGE made the decision to begin using year-end balances for all rate base components.

Q. Is using a year-end approach to rate base items a fair approach to rate making?

A. Yes. Using year-end for all rate base components reflects PGE's rate base just prior to the point at which prices are updated for customers. That is, all amounts included within PGE's net plant balance and overall rate base, are presumed to be used and useful consistent with ORS 757.355 as they are in-service prior to prices being updated.

Q. Is PGE over-collecting on its rate base by using year-end balances?

A. No. A simple review of PGE's results of operations demonstrates that PGE's method does not result in an over-collection from customers. As provided in PGE Exhibit 1702, the prior year-end rate base as determined by PGE's annual results of operations reporting from 2014 through 2022 as compared to PGE's final rate base in applicable general rate case years (e.g., 2014 actual year-end rate base compared to 2015 GRC approved), clearly shows that PGE's actual rate base trended higher in every single period. With the exception of 2016, in which PGE's Carty Plant came online mid-year and was tracked into prices, the same is true when comparing PGE's approved rate base versus average rate base over the same year (e.g., 2015 actual average rate base compared to 2015 GRC approved). All else equal, these results demonstrate PGE is not over-collecting. Rather, PGE is consistently subject to regulatory lag.

Q. Would Staff's proposal result in PGE under-collecting on its rate base?

A. Yes. Staff's one-sided proposal would significantly impair PGE's ability to earn a fair and reasonable return on its investments, as PGE would persistently under-collect on prudently incurred rate base.

Q. Please summarize your response to Staff's testimony and proposal regarding the use of average rate base.

A. Staff's proposal is not the method that any utility in Oregon currently uses or has historically used to set rate base amounts within a general rate case. In short, what Staff proposes is not what has commonly been referred to in Oregon as the average rate base approach. Staff's proposal is misguided, unbalanced, unsupported, and based on a misinterpretation of prior practices. PGE's testimony has demonstrated that our current practice for establishing rate base amounts within a general rate case is consistent and compliant with ORS 757.355 and that if Staff's recommendation were adopted, it would result in a systemic and persistent under-collecting of PGE's prudently incurred rate base amounts. For these reasons and the reasons discussed above, PGE recommends that the Commission reject Staff's proposal and find that PGE's year-end method of setting test year rate base is in accordance with Oregon statutes.

III. Average Rate Base

Q. Please restate Staff's argument and recommendation regarding PGE's method for determining rate base.

A. Staff continues to argue that PGE should not determine rate base using year-end point in time values but instead should use a method they propose and incorrectly term the "average of monthly averages" method. Specifically, Staff's method uses PGE's filed year-end (i.e., 12/31/2023) amount for net plant, which includes a full year of depreciation, and then effectively adds another half year of accumulated depreciation using PGE's total filed depreciation expense, which they state is an approximation of average accumulated reserve over the test period (i.e., 1/1/2024 through 12/31/2024). This proposed approach incorrectly utilizes misaligned periods (2023 vs. 2024) and methods (point-in-time vs. over time) that result in an inequitable and unbalanced view of PGE's rate base.

While PGE provided evidence to the contrary, Staff continues to state as support for their argument that this is the Commission's "favored method"[8] and disagrees with PGE's testimony demonstrating that Staff's method has never been used. Additionally, Staff argues their method is more accurate for capturing PGE's actual rate base over the test period and that PGE's year-end method, which is also used by other utilities in Oregon and is the most commonly used method in the state, effectively allows PGE to over-recover by roughly 36 basis points of its authorized return on equity (ROE).

[8] Staff/3200, Stevens-Young/5.

Q. Has Staff made any adjustments from their initial round of testimony?

A. Yes. Staff has revised the revenue requirement effect of their adjustment to be $15.7 million from $21.7 million in their opening testimony, though it is unclear in their testimony what led to this difference.

Q. Do any other parties support Staff's rate base arguments?

A. Yes. AWEC has also provided testimony that is supportive of Staff's proposal while recommending for the first time in rebuttal testimony an additional $11.6 million reduction to PGE's depreciation expense.[9]

Q. Was it appropriate for AWEC to recommend a new adjustment in its rebuttal testimony?

A. No. The Commission requires five rounds of testimony in general rate cases so that Staff and intervenors can identify disagreements with the Company's filing in their first round of testimony and then address the utility's detailed response in their second round of testimony.[10] Through this process, the issues become "more sharply focused" as the case progresses.[11] By identifying a new issue in rebuttal testimony, AWEC undermined the Commission's established process and the agreed-upon schedule. In addition, AWEC's timing provided PGE with limited time to respond and wholly deprived other parties of an opportunity to respond.

Q. Does Staff's proposed method actually derive an average rate base amount as it has been commonly used in Oregon in the past?

A. No. While Staff uses the term "average rate base," it is a misnomer, as we demonstrated in PGE Exhibit 1700. Staff is not calculating a 13-month average of 2024 rate base amounts

[9] AWEC/600, Mullins/2-6.
[10] *In the Matter of Avista Corp. Request for a Gen. Rate Revision*, Docket UG 288, Order No. 16-109 at 22 (Mar. 15, 2016).
[11] *See Id.*

because estimating monthly changes to rate base with no assumption of changes to capital amounts is not reflective of actual rate base over the test year. In fact, Staff's method does not accurately reflect PGE's rate base at any point in time. Staff's method artificially reduces PGE's total rate base to a level that is not reflective of PGE's past, current, or future rate base amounts and thus does not reasonably reflect the assets PGE has invested in to prudently serve customers.

Q. Please describe Staff's proposed method.

A. Staff's proposal isolates a specific component of PGE's net plant (i.e., the "net" or credit component) and carries that amount forward into the test year such that these credit amounts continue to accumulate. At the same time, Staff argues that continuing investments over the same period of time (i.e., the "plant" component of net plant) cannot and should not be carried forward. As a result, what Staff derives is not actually reflective of net plant nor is it an actual average of averages rate base amount.

Q. What is the impact of using Staff's proposed method?

A. Staff's method mismatches time periods and results in a non-sensical rate base amount that in no way reflects PGE's actual rate base. Specifically, Staff's method produces a rate base amount that will always be below what PGE currently reflects or is expected to reflect on its balance sheet. This ensures that, while customers will receive the benefits associated with PGE's investment in its system, they will not be fully paying the costs associated with this investment.

Q. Would it ever make sense for PGE or any other business to reflect its actual balance sheet amounts in the manner Staff proposes?

A. No. Reflecting financial statements in the manner Staff proposes would violate Generally Accepted Accounting Principles (GAAP). Specifically, Staff's method would violate the principle of periodicity and the principle of consistency. In short, GAAP is foundationally based upon ten key principles. The principle of periodicity establishes that accounting entries should be distributed across the appropriate periods of time. The principle of consistency ensures that consistent standards are followed in financial reporting from period to period to ensure financial comparability between periods. Staff's method neither matches the periods of time nor is it consistent with balance sheet reporting at either a point in time or over time.

Q. Does PGE reflect rate base within its results of operations reporting in the manner Staff proposes?

A. No. PGE's rate base is reflected consistently across time periods. That is, the time periods for gross plant, accumulated depreciation, and accumulated deferred income tax all match (as do the time periods for other rate base items).

Q. Is Staff's adjustment associated with any argument of imprudence related to PGE's invested capital?

A. No. Staff's recommendation and adjustment have no association with any prudence determination. If adopted, it would reduce PGE's prudent rate base amounts by $170 million without any claim or showing of imprudence.

Q. Is Staff's proposal a method that has ever been approved by the Commission or used by any regulated utility in Oregon?

A. No. Contrary to their claim and based on PGE's research, the methodology Staff is proposing has never been used by any utility in Oregon and is unlikely to have been used by any other state commission. When PGE requested that Staff provide evidence of their method having been in use, they were unable to provide a single example.[12]

Q. Does Staff acknowledge that the method they propose has never been used?

A. No. Even though Staff cannot provide any example of their specific method having been used, they continue to inaccurately represent that their method is the Commission's "favored" method. However, Staff now appears to concede that their proposal is not the traditional average of monthly averages approach by characterizing their method as "modified."[13]

Q. Has PGE demonstrated that the method used previously by both PGE and PacifiCorp is in fact not what Staff is proposing?

A. Yes. We have clearly and thoroughly demonstrated using the historical record that the average method used by Oregon utilities prior to the change to year-end also included average plant additions over the test period and that this approach was authorized through a Commission ruling made subsequent to every Commission order Staff cited in their opening testimony.[14] In contrast, Staff's proposal in this case would not include plant additions, resulting in an artificially reduced rate base. As the record on this was established in PGE Exhibit 1700 and Staff has made no attempt to respond to the facts presented, we will not repeat them here. However, we will highlight that, since Order No. 79-055 interpreted the term "presently in-

[12] Staff's response is provided as PGE Exhibit 3501.
[13] Staff/3200, Stevens-Young/5 at 8.
[14] PGE/1700, Batzler-Ferchland/13-21.

service" to mean that "[a] near future test period is clearly allowed,"[15] we are unaware of any subsequent Commission order interpreting this language differently. Thus, PGE believes that if an average of averages method were to be used, not only is it balanced and logical to follow the matching principle and include <u>all</u> components of net plant, including the 13-month average of plant additions over the test year, according to Order No. 79-055, it is allowable under the statute.

Q. Staff claims that PGE's current method for establishing rate base allows PGE to over-recover. Is their support for this claim convincing?

A. No. While Staff may accurately calculate an ROE basis point amount associated with their proposal, this calculation does nothing to prove PGE is over-recovering. In fact, because PGE's actual rate base is expected to grow larger (not smaller per Staff's methodology) post-2023, Staff's example provides an estimate of the additional basis point *deficit* PGE would face compared to our authorized ROE. That is, should Staff's mismatched proposal be adopted and using the numbers they provide, the Commission would be guaranteeing that PGE will underearn its authorized ROE by roughly 36 basis points due directly to this change in methods.

Q. Please explain why Staff's proposal will inhibit PGE's ability to earn its authorized ROE.

A. PGE has two relevant benchmarks for demonstrating that Staff's proposal will erode PGE's ability to earn its authorized ROE.

First, as we explained in PGE Exhibit 2800,[16] PGE has predominately under-earned its ROE over the last 20 years. In fact, as Table 1 of PGE Exhibit 2800 illustrates, PGE has under-

[15] *In the Matter of Revised Tariff Schedules applicable to electric service in the State of Oregon, filed by Portland General Electric Company*, Docket UF 3443, Order No. 79-055 (Jan. 25, 1979) 9.
[16] PGE/2800, Sims-Outama/26 at Table 1.

earned its authorized ROE in 16 of the last 20 years, and none of the four years in which PGE over-earned its ROE occurred post-2015 when PGE changed rate base methodologies. As Table 1 below demonstrates, PGE has underearned in every rate case year by a significant amount (117 bps on average), since switching to the year-end rate base method. For comparison purposes, Table 1 also includes the four prior rate case years of 2007, 2009, 2011, and 2014, during which PGE forecast rate base using the average of averages method. As can be clearly seen, during those rate case years PGE both under and over-earned, whereas, since the change to year-end, PGE has persistently under-earned in every test year.

Table 1
Basis Point Impact of Authorized vs. Actual rate Base

Test Year	Rate Base Method	Regulated ROE	Authorized per Rate Case	Basis Point Difference
2007	Average	11.58%	10.10%	148
2009	Average	8.27%	10.00%	(173)
2011	Average	11.00%	10.00%	100
2014	Average	9.51%	9.75%	(24)
2007-2014 GRC Test Year Average				**13**
2015	Year-End	8.18%	9.68%	(150)
2016	Year-End	8.60%	9.60%	(100)
2018	Year-End	8.53%	9.50%	(97)
2019	Year-End	8.44%	9.50%	(106)
2022	Year-End	8.19%	9.50%	(131)
2015-2022 GRC Test Year Average				**(117)**

Second, PGE's method of calculating rate base is not causing it to over-earn. As there are many reasons other than the difference between PGE's authorized and actual rate base that could be causing this persistent under-earning, we isolate this specific component of PGE's cost structure. We partially addressed this in our reply testimony to Staff by providing a comparison of PGE's actual rate base amounts against forecasted amounts in each general rate case from 2014 through 2022. This analysis, which Staff did not address, was provided as PGE Exhibit 1702 and demonstrated that since PGE moved to the year-end method, approved rate base has been lower than the average rate base for the same year. The only exception to this was 2016; however, this can be explained by PGE's Carty plant, which did not come into customer prices, nor PGE's actual rate base, until midway through the year. After ratably adjusting for Carty, 2016's approved rate base is also lower than PGE's actual average regulated rate base.

Table 2 below illustrates and quantifies the impact of PGE's approved versus actual rate base. As can be seen below, of the 117 average basis point difference between PGE's authorized and actual ROE in Table 1 above, approximately three-quarters of the variance, or 76 basis points, is attributable to PGE's actual average rate base coming in greater than amounts approved. Additionally, for comparison purposes, we have included the calculated results for PGE's last rate case prior to the move to year-end rate base. As can be seen, there is a much smaller difference between approved and actual rate base amounts.

Table 2
Basis Point Impact of Authorized vs. Actual Rate Base

Test Year / ROO Year	Docket	Rate Base Method	Authorized Rate Base(4)	Actual Average Rate Base	Difference	ROE Basis Point Impact
2014	UE 262	Average	3,054,217	3,105,774	51,557	(26)
2015	UE 283	Year-End	3,785,421	4,009,617	224,196	(80)
2016	UE 294(1)	Year-End	4,143,584	4,268,624	125,040	(42)
2018	UE 319	Year-End	4,505,374	4,863,447	358,073	(105)
2019	UE 335	Year-End	4,744,710	4,949,366	204,656	(57)
2022	UE 394(2)(3)	Year-End	5,287,621	5,681,061	393,440	(97)
Average 2015-2022 bps impact:						**(76)**

(1) Ratably adjusted for the Carty Tracker
(2) Includes Colstrip
(3) Ratably adjusted for May 2022 price effective date
(4) PGE notes that, if using Staff's method, "authorized rate base" would be lower every year, resulting in a greater difference

Staff argues that PGE's method "over collects because rates are set based on a rate base value that is appreciably greater than the actual average rate base value during the test period."[17] As these results clearly demonstrate, PGE is neither over-earning in general nor are we over-earning as a result of our current method for calculating a test year rate base amount.

Q. Staff makes a point of stating that the "Test Year is intended to be representative of the Company's normal operations."[18] Does PGE agree?

A. We do, which is why we fundamentally disagree with Staff's proposal. As we demonstrate above, PGE is neither over-collecting broadly nor are we over-collecting on our test year rate base. In fact, the historical evidence provided above demonstrates the opposite. PGE's current method for establishing rate base already leads to a systematic under-collection, and if Staff's proposal is adopted, this persistent under-collection will grow larger. PGE should be afforded the *opportunity* to earn its authorized ROE. Adopting Staff's unbalanced method will make this exceedingly difficult.

Q. Is PGE's position that Staff's method mixes and matches year-end numbers with average numbers a "red herring" as Staff suggests?

A. No. PGE's statement that Staff is mixing and matching time periods is neither intended to mislead nor distract from the faults of Staff's proposal. Staff either fails to understand or refuses to recognize the point we are making. We are not arguing over the precision of Staff's numbers. We are arguing over the fundamental premise of Staff's proposal. The "mixing" and "matching" in Staff's proposal is both an issue of time periods (i.e., using a 2023 amount for capital additions versus a 2024 amount for accumulated depreciation) and of amounts at a "point in time" (i.e., December 31, 2023 for capital) versus amounts "over time" (i.e., January 1, 2024 through December 31, 2024 for accumulated depreciation). Not only are

[17] Staff/3200, Stevens-Young/8 at 14-16.
[18] *Id.*/5 at 20-21.

the methods misaligned, but the years are misaligned. The result reflects two mismatched periods that in no way are reflective of PGE's actual net plant balance at any time.

Q. Does Staff address the evidence that PGE presented regarding the fact that both PGE and PacifiCorp, Oregon's two largest utilities, have used the year-end method for approximately 10 years and that Staff clearly recognized this change in method when PGE employed it, and found it to be reasonable?

A. No.

Q. Staff notes in their testimony that Avista recently accepted a settlement proposal that is aligned with what Staff proposes for PGE. How do you respond?

A. Setting aside the fact that Avista's settlement has yet to be adopted by the Commission, we would note that Avista did not file *any* responsive testimony in UG 461. That is, Avista settled the entirety of their rate case without formally responding to any party testimony. Additionally, Avista reserved the right in a future proceeding to address the issue.

Q. What incentive might Avista have to simply settle this issue with Staff?

A. Avista's incentive may be one of efficiency. Avista serves utility customers in three states and Oregon comprises a very small share of Avista's total revenue base. According to their initial filing in UG 461, Avista's total Oregon revenue requirement requested was approximately $84.7 million.[19] This amounts to approximately 6.5% of their total gas and electric retail revenues[20] and equates to approximately 3.2% of PGE's total requested revenue requirement in this proceeding. The impact to Avista from this change is likely immaterial to their overall operations, and thus it would appear that expediency took priority in adjudicating their Oregon

[19] *In the Matter of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision*, Docket UG 461, Avista/501, Schultz/1.
[20] UG 461, Avista/100, Vermillion/3. Total gas and electric retail revenues of $1,305 million.

general rate case request. Again, we would note that Avista reserved the right to address the methodology in the future, which shows that they were not necessarily agreeing to Staff's premise with their settlement.

Q. Did Avista include any 2024 test year capital amounts within their Oregon rate case filing?

A. Yes. Contrary to Staff's interpretation of ORS 757.355, Avista did include certain 2024 capital amounts within their 2024 test year request, which were ultimately included as part of their stipulated outcome.[21]

Q. Is there support for PGE's contention that Staff's proposed method will violate Normalization Rules?

A. Yes. 26 U.S.C. § 168(i)(9)(B) provides that the Normalization Rules are not satisfied if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which uses an estimate or projection of tax expense, depreciation expense, or a reserve for deferred taxes unless such estimate or projection is also used with respect to the other two items and with respect to rate base. This prohibition is generally referred to as "the Consistency Rule." Using the misnamed "average-of-averages" method proposed by Staff will violate the consistency rule because Staff proposes to change rate base without changing the projection of tax expense, depreciation expense, and the reserve for deferred taxes. In other words, Staff proposes to change one of the four items that must be kept in sync without adjusting the other three.

Q. Are there any other Normalization Rules that would be violated with Staff's recommended change in rate base?

[21] See UG 461, Staff/200, Chipanera/7 at 17-19 and Second Settlement Stipulation, Table No. 3, part f.

A. Yes. Treasury Regulation 26 C.F.R. § 1.167(l)-1(h)(6)(i) makes it clear that the reserve excluded from rate base must be determined by reference to the same period as is used in determining ratemaking tax expense. Therefore, a taxpayer may use either historical data or projected data in calculating these two amounts, but they must be consistent. As explained in 26 C.F.R. § 1.167(l)- 1(a)(1), the rules provided in § 1.167(l)-1(h)(6)(i) are to ensure that the same time period is used to determine the deferred tax reserve amount resulting from the use of an accelerated method of depreciation for cost of service purposes and the reserve amount that may be excluded from the rate base or included in no-cost capital in determining such cost of services. The change proposed by Staff moves the calculation of rate base to a different period from the one used to calculate deferred taxes.

Q. AWEC claims that PGE's approach to year-end rate base "results in an inconsistent revenue requirement because it is capturing escalated expenses but not the corresponding accumulated depreciation in the Test Period."[22] Is their argument valid?

A. No. AWEC is fundamentally mixing concepts when PGE's test year is in fact entirely consistent. Specifically, for balance sheet items, which reflect point-in-time values, PGE has consistently forecast all of them at December 31, 2023, which is one day prior to PGE's price effective date and consistent with ORS 757.355. For income statement items, PGE reflects these amounts over time assuming a calendar year 2024 (i.e., PGE's forecast test year). There is no "corresponding accumulated depreciation" to PGE's 2024 test year expenses outside of depreciation expense, which we have already taken into account. AWEC's recommendation is based on a number of incorrect statements regarding how PGE calculates depreciation expense.

[22] AWEC/600, Mullins/3 at 18-20.

Q. How does AWEC claim that PGE calculates depreciation expense?

A. AWEC states that PGE's depreciation expense is "effectively calculated on a forward-looking basis over calendar year 2024."[23] However, this is incorrect as there are no 2024 plant amounts included within PGE's test year and thus no corresponding 2024 depreciation expense.

Q. AWEC describes PGE's method of annualizing depreciation amounts associated with new capital additions for 2023 to claim that PGE's approach is a mismatch of 2023 and 2024 depreciation expenses.[24] Is AWEC's understanding accurate?

A. No. AWEC's description excludes key details. Specifically, as we describe in PGE Exhibit 1700, new depreciation expense for 2023 is also assumed at a full year (i.e., annualized) for purposes of establishing accumulated depreciation in rate base. PGE Exhibit 200, Section III clearly describes how PGE's depreciation expense is both aligned with our requested rate base <u>and</u> PGE's 2024 test year for expense.

Q. Did Staff review PGE's depreciation expense?

A. Yes. Staff reviewed PGE's depreciation expense in detail and specifically discussed PGE's calculation and method for determining test year depreciation expense in Staff Exhibit 1700. After discussing their review of PGE's depreciation expense in detail over several pages, Staff ultimately states that "PGE complied with the Commission Order No. 21-463, and its calculated depreciation expense is reasonable."[25] Staff goes on to state that they "do not make an adjustment to PGE's depreciation expense in UE 416."[26]

Q. Has PGE forecast a rate base amount that assumes the average of averages methodology for gross plant, accumulated depreciation, and accumulated deferred income taxes,

[23] *Id.* 3 at 3-4.
[24] *Id.*/4.
[25] Staff 1700, Peng/10 at 19-20.
[26] *Id*. at 20-21.

similar to the methodology PGE and PacifiCorp used prior to moving to the current method?

A. Yes. PGE has recently conducted its capital budget process for 2024 and using these results, we have developed a preliminary forecast of total net plant (i.e., gross plant, net of accumulated depreciation and accumulated deferred income taxes) and depreciation expense, that is consistent with normalization requirements, using the average of averages methodology as allowed by Commission Order No. 79-055 and used by PGE and PacifiCorp prior to each utility's change to the year-end method.

Q. What is the result of this forecast?

A. This draft analysis using PGE's 2024 preliminary capital forecast results in an increase of $277.8 million to PGE's filed rate base amounts and a $4.5 million increase to PGE's filed depreciation expense. If PGE were to have filed its 2024 test year using the average rate base method historically employed by Oregon utilities following Order No. 79-055, our total revenue requirement request would have been approximately $30.5 million greater. Table 3 below provides these results.

Table 3
Year End vs. Average of Averages Results (millions)

	Year End Method (As Filed)	**2024 Average of Averages**	**Delta**
Gross Plant	12,249.5	12,650.0	400.4
Accum. Reserve	(5,441.3)	(5,552.1)	(110.8)
Accum. Def Tax	(667.3)	(676.6)	(9.4)
Net Utility Plant	**6,140.9**	**6,421.2**	**280.3**
Depr/Amort Exp.	**422.6**	**427.1**	**4.5**
Sales to Consumers	**1,004.9**	**1,035.4**	**30.5**

Q. Does this mean that PGE could have responded to OPUC Data Request No. 819?

A. No. PGE did not "refuse[] to respond" to this data request, as Staff states within their testimony.[27] In fact, as we clearly stated in our response to Staff, the request asked for "information that PGE has not prepared or forecast and that is not included within this proceeding." We continued by stating that "using an average of averages for 2024 accumulated depreciation and accumulated deferred income taxes (ADIT), requires a monthly forecast of plant closings from January 1 through December 31, 2024, which PGE has not yet developed as PGE has based its current request on plant closings as of December 31, 2023."[28] We did not provide the above information because, as we explained in our response to OPUC Data Request No. 819, we did not yet have a budget or forecast from which to calculate the requested information. In fact, this information only became available in draft form at the end of July, which is the normal time when preparing budgets for the following year. As such, PGE has now supplemented its response to OPUC Data Request No. 819, consistent with the information presented above in Table 3.

Q. Are there any other unintended consequences of making an abrupt shift to a new and not broadly used or supported methodology?

A. Yes. A change such as this, which is clearly non-representative of PGE's prudently invested capital, will likely signal to investors that PGE is a riskier investment relative to our peers. Utility investors favorably view regulatory jurisdictions that consistently apply ratemaking methodologies that enable a reasonable ability to earn near the allowed rate of return. Staff's proposal would be a change from methodologies applied in previous rate cases and erodes PGE's ability to earn at its authorized ROE. As such, the risks of investing in PGE will

[27] Staff/3200, Stevens-Young/2.
[28] PGE's response is provided in full as Staff/802.

increase relative to our peers, while the rewards, particularly authorized ROE, will not, thus impacting investor decision-making. While this may not serve as reason alone for the Commission to reject this change, it should be considered that an unintended consequence of adopting this mis-matched method for a $170 million downward adjustment to rate base will likely be a negative investor reaction, impacting PGE's ability to effectively access capital markets and raise cost-effective capital.

Q. What does PGE request of the Commission?

A. We request the Commission recognize PGE's year-end method for establishing its test year net utility plant and depreciation amounts as reasonable and that the Commission decline to adopt Staff's or AWEC's proposals regarding this issue. ORS 756.040 provides that "[t]he commission shall balance the interests of the utility investor and the consumer in establishing fair and reasonable rates." And that "[r]ates are fair and reasonable […] if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility." PGE has clearly demonstrated that adopting these proposals will result in rate base and depreciation amounts that are not reflective of the test year and are not fair and reasonable, which will lead to persistent and systematic under-earning, with the end result being that PGE will almost certainly under-recover its prudent investments used to serve customers.

UE 435

Exhibit 1303 contains confidential information and is subject to

General Protective Order 23-132

May 17, 2024

To: Bob Jenks
Oregon Citizens' Utility Board

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to CUB Data Request 029-CONFIDENTIAL
Dated May 3, 2024

Request:

Please provide all documents, including but not limited to workpapers or workbooks, the Company used to explore different Investment Tax Credit (ITC) amortization options.

Response:

Confidential Attachments 029-A and 029-B provide the requested information. The attachments show the analysis that was previously performed and should not be relied upon for accuracy of amounts.

Attachments 029-A and 029-B contain confidential information and are subject to general protective Order No. 23-132.

operating_un	operating_unit_descriptio	account	account_description	Acct combined	6/30/2024
12100	Boardman - PGE Only	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ -
14100	Beaver	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 2,701,843
15200	Faraday	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ (185)
15300	North Fork	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ -
15400	Oak Grove	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 185
16100	Coyote Springs 1	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 1,219,053
16400	Port Westward 1	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 5,180,810
16600	Port Westward 2	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 2,787,238
16800	Carty	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 2,105,827
17200	Biglow Canyon	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 13,487
18100	PGE General Operations	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 65,836,107
86100	Coyote Springs	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ (7,489)
86200	Coyote Springs credit	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 128
92100	Boardman	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 888
92200	Boardman credit	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ (89)
92500	Boardman 15%	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ -
95599	Coyote Unit 2 Passthrough	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ -
99100	Round Butte Project	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ 399,400
99200	Round Butte credit	1540001	Plant Materials and Supplies	1540001-Plant Materials and Supplies	$ (141,510)
11100	PGE ONLY - Trojan	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -
12100	Boardman - PGE Only	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -
14100	Beaver	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ (788)
15200	Faraday	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -
15300	North Fork	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -
15400	Oak Grove	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -
15500	River Mill	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -
15800	Sullivan	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -
16100	Coyote Springs 1	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ 1,439
16400	Port Westward 1	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ (63)
16600	Port Westward 2	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ 396
16800	Carty	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ (342)
17200	Biglow Canyon	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -
17400	Tucannon River Wind	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -
18100	PGE General Operations	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ 4,491,781
86100	Coyote Springs	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ (10)
86200	Coyote Springs credit	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ 1,823
91100	Trojan	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ (2)
91200	Trojan Credit	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ 1
92100	Boardman	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$ -

92200	Boardman credit	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$	-
92500	Boardman 15%	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$	-
95400	Port of St. Helens	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$	(19)
95599	Coyote Unit 2 Passthrough	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$	-
96100	Pelton Project	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$	-
96200	Pelton credit	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$	(114)
99100	Round Butte Project	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$	4,241
99200	Round Butte credit	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$	(1,311)
99999	Intercompany Elim OU	1630001	Stores Expense - Undistributed	1630001-Stores Expense - Undistributed	$	7,724
					$	84,600,452

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Corporate Support & Total Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Anne Mersereau
Ryan Van Oostrum
Greg Batzler

August 14, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Anne Mersereau. My position is Vice President, Human Resources, Diversity, Equity & Inclusion at PGE. My qualifications appear at the end PGE Exhibit 300.

My name is Ryan Van Oostrum. I am employed by PGE as Director Controller. My qualifications appear in Section VI below.

My name is Greg Batzler. I am employed by PGE as a Senior Regulatory Consultant in Regulatory Affairs at PGE. My qualifications appear at the end of PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues and proposed adjustments raised by the Staff of the Public Utility Commission of Oregon (Staff), the Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens' Utility Board (CUB) (collectively, Parties) with respect to PGE's Total Compensation, IT Capital Additions, and Administrative and General (A&G) 2025 Test Year request.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II – Overview & Summary
- Section III – Total Compensation
- Section IV – IT Capital Additions
- Section V – Corporate Support
- Section VI – Qualifications

II. Overview and Summary

Q. Please provide an overview of the Parties' proposals regarding PGE compensation.

A. Both Staff and AWEC propose large reductions to PGE's wages and salaries. Staff applies two adjustments: one related to their 3-Year Wages and Salaries model and another related to PGE's Full-Time Equivalent (FTE) employment level. Staff's adjustments amount to $31,866,262 in proposed reductions. Similar to Staff's FTE adjustment, AWEC argues that PGE's FTE count should be limited to our 2023 actuals, resulting in a proposed reduction of $34,238,543.

Regarding incentives, the Parties seek reductions of various amounts. Staff proposes two adjustments, one stemming from historical actuals and another related to capitalized incentives, that totals to a reduction of $3,668,322. CUB and AWEC both propose that PGE no longer recover funds related to stock award incentives, which amounts to a reduction of $3,667,739. AWEC additionally proposes a change in the manner in which PGE allocates incentives, resulting in a $4,215,918 proposed reduction. Finally, CUB, suggests that PGE only be allowed recovery on 25% of cash incentives, resulting in a proposed reduction of $7,128,743.

Q. Please summarize PGE's response to the Parties' compensation-related proposals.

A. PGE recommends that the Commission reject all of the Parties' proposed adjustments. Their proposed reductions in PGE's staffing levels will unduly hurt customers and PGE. Moreover, incentives remain an important part of a market-competitive pay package that supports PGE's efforts to attract and retain employees who are best equipped to serve our customers.

Q. Please summarize the Parties' proposals regarding PGE administrative and general expenses for the 2025 test year.

A. Staff proposes adjustments to multiple areas of A&G including:

1. A $7,755,769 reduction across all categories of PGE's 2025 test year insurance forecast;
2. A $1,780,000 million reduction to FERC account 921, Office Supplies;
3. A reduction of directors' and officers' insurance of $219,473;
4. A reduction to memberships of $301,984; and
5. A reduction to meals and entertainment of $142,608.

Staff further states that they have outstanding data requests regarding FERC account 920 and has not reached a conclusion regarding the account.

AWEC proposes an overarching reduction to A&G of $4,585,715. Then, in other parts of their testimony, AWEC proposes additional reductions to specific elements of A&G for directors' and officers' insurance and expense, brokers fee, net margin interest, and revolving credit facility fees, which result in an additional $6,787,133 of reductions to PGE's test year expense.

Q. Please summarize your response to Staff and AWEC's proposals regarding A&G.

A. PGE requests that the Commission reject Staff's proposals to reduce A&G in the areas of insurance, FERC account 921, and directors' and officers' (D&O) insurance. PGE's insurance portfolio is a shield that serves to protect customers and PGE from financial instability, while our forecasts for FERC account 921 and D&O are fully supported. We further request that the Commission decline entertaining new proposals from Staff regarding FERC Account 920 or Property Insurance. All data requests related to both matters were provided by PGE to Staff well in advance to the filing of Staff's testimony. PGE accepts Staff's proposed reduction to meals and entertainment, and a portion of Staff's proposed reduction to memberships.

PGE also requests that the Commission reject AWEC's proposed reductions. First, it is redundant to recommend an overarching reduction to an entire category of expense and then return to the category and make proposals to cut individual items. This double-count should nullify AWEC's general proposal. Further, as discussed in detail below, we find their proposals to reduce brokers fee, net margin interest, and revolving credit facility fees to be an overreach of previously established treatment of these costs that do provide value to customers.

III. Total Compensation

Q. Please describe PGE's Total Compensation structure and philosophy.

A. PGE's Total Compensation package is built around providing our employees with comprehensive, market-competitive compensation that supports PGE's efforts to attract and retain qualified candidates. This market-competitive compensation package includes wages and salaries, incentives, and benefits that include a retirement savings plan, health and wellness solutions, and tuition assistance.

Q. How does a market-competitive compensation package benefit PGE customers?

A. A market-competitive compensation package attracts and retains qualified personnel. Attracting and retaining staff at adequate levels is necessary to ensure that the Company can operate a safe, reliable, and resilient system that customers expect and depend on.

A. Labor Costs

Q. Please summarize PGE's Test Year labor costs.

A. PGE forecasts approximately $470.4 million in aggregate labor costs for the 2025 test year, which represents a 6.6% increase from 2024 budget, or a 4.3% compound annual growth rate from 2023 to 2025.

Table 1
Total Aggregate Labor Costs by Cost Category ($000)

	2023 Actuals (1)	2024 Budget	2025 Test Year (3)
Salaried Straight Time	$204,136	$223,922	$238,846
Union Straight Time	$68,053	$74,356	$80,648
Hourly Straight Time	$17,680	$21,535	$22,343
Union Overtime	$27,014	$20,163	$21,306
Hourly Overtime	$1,378	$962	$1,083
Temporary PGE Labor	$2,628	$2,299	$2,386
Contract Labor	$60,480	$37,573	$40,083
Paid Time Off (PTO)	$51,252	$56,237	$59,249
Total Wages & Salaries (2)	**$432,621**	**$441,240**	**$470,372**

(1) Actuals do not include Level 3 storm outage labor.
(2) Numbers may not sum due to rounding.
(3) 2025 amounts are net of PGE's pre-filing adjustments.

Q. Please describe how PGE adjusted this figure to reflect 2025 Test Year expenses.

A. There are two pre-filing adjustments that PGE utilized to form our 2025 Test Year forecast for Total Labor expense. The first is our unfilled position adjustment, which we traditionally make as a proxy for approximately 100 FTE employees. The second is our adjustment to straight-time labor to account for shifts in our actuals to contract labor. To more accurately reflect the Company's expectations for the 2025 Test Year, PGE reallocated $14.0 million initially forecast to straight-time labor to contract labor.

Q. Does any Party object to PGE's 2025 Test Year adjustment?

A. Yes, Staff and AWEC object, with Staff claiming a history of mis-budgeting[1] and AWEC asserting that the effect of the adjustment is unclear.[2] Additionally, AWEC erroneously asserts that PGE's $14.0 million dollar adjustment to shift straight-time labor to contract labor increased PGE's labor expenses for the 2025 Test Year.

Q. Does PGE's $14.0 million adjustment to straight-time labor increase PGE's expenses for the 2025 Test Year forecast?

A. No. As we state above, it simply reallocates funds from straight-time labor to contract labor to better reflect and represent PGE's 2025 Test Year workforce expectations.

Q. Are PGE's pre-filing adjustments "undocumented and largely arbitrary?"[3]

A. No. The $14 million adjustment was informed by an average of historical actuals (i.e., 2021-2023 budget to actual variances between straight-time and contract labor). On average from 2021 through 2023, PGE's straight-time labor budget was $14.5 million above actual costs, while PGE's contract labor budget was $24.5 million below actual costs over the same

[1] Staff/1200, Yamada/7 at 1-5.
[2] AWEC/100, Mullins/40 at 5-10.
[3] *Id.* 41 at 1-7.

period.[4] Indeed, AWEC cites PGE's Response to OPUC Data Request No. 273, which includes a detailed description of the adjustment and shows precisely how the reallocation of $14.0 million was calculated.

Q. Does this reallocation "artificially reduce"[5] PGE's request in this case?

A. No. This labor adjustment merely reallocates expenses from one account and to another. The purpose of this adjustment is to utilize historical data to reflect a more accurate Test Year forecast, while continuing to allow PGE to internally budget for regular full-time employees, who are ultimately best suited to fill the long-term needs of these roles.

Q. Why did PGE reflect this shift in the Test Year forecast?

A. We reflected this labor shift to better represent the expectations of our Test Year labor composition, as supported by the most recent three years of actual data. PGE continues to face challenges in finding qualified candidates for many of our critical job functions, and often finds it difficult to fill roles that require certain levels of expertise or qualifications. As a result, contract labor, along with increased overtime from existing employees, is an important tool to support necessary work. While PGE is aware that contract labor will be used to replace regular full-time employees throughout a budget year, we cannot divine exactly which positions. As such, PGE budgets in a manner that allows our managers to fill positions with PGE labor while recognizing that some of those managers will supplement those roles that cannot be filled in a timely manner with contract labor.

Q. What is the historical correlation between straight-time and contract labor?

A. Historically, when PGE's straight-time labor actuals are below budget, PGE's contract labor actuals are above budget. This correlation reflects the connection, described above, between

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[4] PGE Exhibit 1401
[5] Staff/1200, Yamada/6 at 10-12.

the difficulty filling internal roles and the need, in such circumstances, to rely on contract labor. As noted above, straight-time O&M labor spending has come under budget by a cumulative $43.5 million over the last three years, prior to factoring in the costs of benefits and other direct loadings, while O&M contract labor spending was $73.6 million over budget during that same timeframe.

Q. Staff argues that costs should not be shifted from straight-time labor to contract costs because "PGE is in control of its own budget[.]"[6] Do you agree?

A. PGE agrees that we control our own budget, and consequently, it is within PGE's control to shift expenses from straight-time labor to contract labor in PGE's Test Year forecast to better reflect how we anticipate dollars to actually be spent within the test year. PGE develops its budget based on a combination of the needs to provide service and the realities of the labor market. PGE's standard department level internal budgets contain positions that sometimes go unfilled, with the work ultimately being performed by contract labor. If PGE's internal budgets did not include those positions, then department managers would not be able to fill the positions when a candidate becomes available. However, PGE's Test Year forecast was adjusted to more accurately represent the actual costs that PGE expects to experience during the period in which the rates will be in effect.

Q. Given that there is no net effect from PGE's adjustment, what is the reason for Staff's objection?

A. Staff objects to the adjustment because it impacts Staff's application of their 3-Year Wages and Salaries model, which focuses on FTE counts rather than a holistic assessment of both internal and contract labor costs.[7] A position that does not reflect the modern and dynamic

[6] Staff/1200, Yamada/7.
[7] *Id*.

labor market to which PGE is subject. Staff's analysis does not review PGE's Total Labor request holistically, instead it looks at two components, specifically straight-time labor and overtime labor, and then adds the total of the negative adjustments proposed by the model together. Staff then analyzes PGE's FTEs separately. In this case, no actual analysis related to contract labor was provided as an exhibit to this case. Staff's proposed adjustment is simply unsupported and should be rejected by the Commission.

Q. How do you respond to Staff's continued insistence on using the 3-Year Wages and Salaries model?

A. We continue to oppose the usage of the 3-Year Wages and Salaries model, while expressing our preference for a holistic evaluation of labor requirements. Contract labor serves to fill the same role and is functionally identical in many ways to regular full-time PGE employees. There is no basis for Staff to utilize a model that does not consider it. PGE must use the resources we have available to complete the critical work associated with delivering energy to our customers. Straight-time labor, overtime labor, and contract labor all serve the same purpose in service of our customers and should be viewed holistically rather than in isolation.

Q. Staff also proposed a separate and distinct downward adjustment based on their proposed FTE count; how does PGE respond?

A. Staff's proposed reduction of 213 FTEs, which equates to approximately $28 million, is excessive and unfounded. The lack of basis for this adjustment also relates to the contract labor issue in testimony above, and why a holistic review is necessary. Staff's position is to hold PGE to 2023 FTE levels, plus an escalation of 0.7% annually. However, in 2023 PGE had 1,423 contract workers, some of whom were fulfilling work that was originally budgeted to be completed by a regular, full-time PGE employee. Staff then uses that variance to propose a reduction of PGE's regular workforce. If a similar reduction in FTE is proposed and accepted PGE would face an ever-shrinking regular full-time workforce, being forced to rely more and more on contract labor after the conclusion of each case and ultimately under-recovering the actual labor costs required to serve customers.

Q. AWEC also proposed a downward adjustment to PGE's 2025 Test Year forecast related to PGE's FTE count; how does PGE respond?

A. Just as with Staff's analysis, AWEC does not consider PGE's labor in a holistic manner. Like Staff, AWEC's proposal does not consider the shift of labor from straight-time to contract labor. However, AWEC relies on an even more simplistic set of analysis, where they believe PGE should be held to a single point in time, with no consideration for new and incremental work PGE encounters to support safety, compliance, and customer needs that result in an increased reliance on contract labor.

Q. If contract labor is an adequate substitute for PGE labor and finding qualified candidates for internal positions is a persistent challenge, why not simply reduce recruitment efforts and become more permanently reliant on a contingent labor force?

A. Contract labor does have drawbacks. The average tenure of PGE's contract labor force is approximately 1.8 years; meanwhile, our PGE employee workforce has spent an average of 10.8 years at PGE. That means that on average a PGE employee has an additional 9 years of direct knowledge and experience and is much more likely to be present to see the long-term effects of their work, creating additional levels of both expertise and connection to the customers that contractors will often not possess. The higher turnover among contract workers also leads to increased onboarding costs, as their short employment tenures necessitate nearly five times more onboarding processes compared to regular employees. Contract labor simply has more costs and inefficiencies compared to a directly employed workforce. However, the value that contract labor holds in our Total Labor requirement is in its flexibility and ability to provide PGE with temporary coverage of roles while we seek out a candidate that can fill a role permanently.

Q. Please summarize PGE's stance on contract labor, and why PGE believes that Total Labor should be considered holistically.

A. Contract labor is an important part of PGE's Total Labor requirements, and Staff's lack of engagement in meaningful and productive solutions to incorporate contract labor to a Test Year forecast while allowing the flexibility to fill PGE positions to complete critical work, undermines our ability to provide our customers with affordable, safe, and reliable energy. Staff and AWEC's proposals, if adopted, would also have detrimental impacts on future rate cases and artificially restrict PGE's ability to directly employ and promote a right-sized workforce at the peril of customers and PGE.

Q. Does PGE have any additional concerns or comments on Staff's testimony and proposed adjustments?

A. Yes. Upon review, PGE has found several inconsistencies within Staff's testimony related to PGE's Total Labor. In Staff Exhibit 1200 Staff proposed the removal of an additional four FTEs above their analysis stating "[a]s discussed in the testimony of Staff witness Luz Mondragon, Staff is recommending the exclusion of four Senior Forester FTEs."[8] However in Staff Exhibit 1300 on this topic Staff states that "Staff Exhibit Yamada will discuss this further in her testimony."[9] As neither testimony actually provides any analysis, or even expresses any

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[8] Staff/1200, Yamada/16 at 2-7.
[9] Staff/1300, Mondragon/13 at 6-9.

beliefs or opinions on the matter, PGE has not been provided a basis as to why Staff proposes their removal in this case.

Additionally, PGE responds in Exhibit 1700 to Staff's proposal to remove $4.0 million from PGE's 2025 Test Year forecast related to incremental O&M spending on virtual power plant (VPP). However, this $4.0 million of incremental spending includes 13 incremental positions, meaning that Staff's proposed reduction to PGE's staffing levels via the FTE adjustment and their proposed reduction relating to VPP contain duplicative amounts of approximately $1.6 million. Another duplicative adjustment is also proposed by Staff in Exhibit 2200, wherein Staff proposes the removal of $993 thousand dollars of O&M related to EV Field Operations, of which approximately $900 thousand is labor and therefore duplicative of Staff's proposed Wages and Salaries adjustment.

Q. Please summarize PGE's stance on Staff and AWEC's proposals.

A. PGE recommends the Commission reject the proposals made by Staff and AWEC. Both Staff and AWEC's analysis lack a holistic review of PGE's Total Labor requirements, while additionally Staff's analysis has produced duplicative adjustments in multiple places in this case. These adjustments would harm PGE and our customers.

B. Incentives

Q. What are incentives?

A. Incentive pay is part of a market-competitive total compensation package. Most incentive pay places a portion of employee pay at risk, making it dependent on the employee's performance and quality of output, along with PGE's overall performance. While incentive pay shares characteristics in common with bonuses, most of PGE's incentive pay is different from a bonus because the "at risk" component is utilized to drive performance and outcomes that benefit PGE's customers. PGE targets the mid-point of the employment market with our incentive program. However, incentive pay allows high-performing employees to be rewarded with a larger total annual compensation package based on pre-established performance goals and some additional rewards for extraordinary achievement.

Q. What is PGE's incentives forecast for the Test Year?

A. Table 2 below outlines PGE's 2025 incentives request in this case. We note that 2025 figures are net of pre-filing adjustments that remove 100% of officer incentives and 50% of non-officer incentives.

Table 2
Total Incentives ($000)

Incentive Plans	**2023 Actuals**	**2024 Budget**	**2025 Test Year(1)**
Annual Cash Incentive (combined ACI/PIC)	$27,865	$31,124	$14,257
Stock (long-term incentive plan)	$16,908	$17,392	$3,668
One-time recognition and Miscellaneous	$57	$23	$12
Total Incentives(2)	**$44,830**	**$48,540**	**$17,937**

(1) *Amounts are net of PGE's pre-filing adjustments.*
(2) *Numbers may not sum due to rounding.*

Q. How do incentives benefit PGE's customers?

A. Incentives are an important part of the robust, market based competitive pay package PGE has developed to attract and retain top talent. If PGE did not provide this industry standard compensation, we would be at a distinct disadvantage when seeking well-qualified candidates to fill open positions at PGE. Customers directly benefit from having a utility that can attract the best possible employees while maintaining adequate staffing levels. Additionally, PGE utilizes incentives to drive results that directly benefit customers, such as customer satisfaction, grid reliability, and generation dependability. If PGE were to discontinue offering incentives, we would likely need to increase base wages to remain competitive, thereby losing that performance-based part of compensation that customers benefit from, which they receive at a discount provided by PGE's 50% sharing of costs.

Q. Please describe Staff's first proposed adjustment to PGE's incentives forecast.

A. Staff's first incentives adjustment, which amounts to $1,796,270, was developed by taking the average amount of actual non-officer incentive expense from the years 2021-2023 and calculating the difference between PGE's 2025 forecast and that amount. This method does not account for either inflation or changes in the employee headcount at PGE.

Q. Is it inconsistent of Staff to propose no escalation of this expense?

A. Yes. PGE's incentives are based upon a set percentage of employee pay, where we typically target a certain percentage of an employees' salary. That means that as wages increase, incentives increase accordingly, which aligns with common practices both within the industry and across the job market, allowing PGE to stay competitive when seeking qualified candidates. Staff's W&S model includes escalation for the 2024 and 2025 years, using inflators of 3.3% and 2.2% respectively.

Q. Would escalating the incentives Staff used to reflect an inflation adjusted 2025 amount make a material difference?

A. Yes. We calculate that PGE's 2025 Test Year forecast is lower than the average of actual 2021-2023 non-officer incentives over the same period when expressed in real (i.e., inflation adjusted) dollars,[10] which implies that PGE under-forecast this expense.

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[10] See PGE Exhibit 1402.

Q. How much of an increase in FTEs does PGE forecast for the 2025 year?

A. PGE forecasts an increase of approximately 5% in 2025 FTEs compared to 2023 actuals. As such, one would expect PGE's inflation adjusted three-year average incentive expense to increase accordingly. This is not the case, which also implies that PGE under-forecast this expense. In fact, PGE calculates that using Staff's three-year average methodology, but including the effects of inflation and changes in total workforce, an appropriate amount for this forecast would have been approximately $18.8 million, almost $1 million more than PGE has requested.[11]

Q. How does PGE respond to Staff's second proposed adjustment?

A. Staff's second proposed adjustment, a reduction of $1,872,052, is entirely erroneous. Staff sent PGE a data request inquiring about capitalized incentives, to which PGE responded that the Test Year rate base includes $3,744,103 of incentives.[12] Staff mistakenly concluded that these incentives were not subject to a pre-filing adjustment, which is incorrect. Consistent with Commission Order No. 14-422,[13] PGE does not capitalize any financial performance-based incentives.

Q. Please summarize PGE's position on Staff's proposed adjustments to incentives.

A. PGE recommends Staff's proposed adjustments be rejected. At PGE, we have developed a prudent competitive pay package that includes a 2025 incentive forecast with a slight decrease in real terms, while incorporating pre-filing adjustments to remove 100% of officer and 50% of non-officer amounts in addition to adjusting capitalizable amounts to ensure compliance with previous Commission decisions.

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[11] *Id*.
[12] Staff/1202, PGE's Response to Staff's DR 265.
[13] *In the Matter of Portland General Electric Company Request for General Rate Revision*, UE 283, Order No. 14-422, Appendix B at 2 (Dec 30, 2014).

Q. Did other Parties recommend any adjustments to PGE's 2025 incentives forecast?

A. Yes. Both AWEC and CUB proposed adjustments to PGE's 2025 incentives forecast. Both parties recommend that PGE remove all incentives in the form of stock awards, citing similar arguments. Additionally, AWEC proposes an adjustment associated with incentives overheads and CUB proposes an additional punitive incentive adjustment for a perceived misalignment between employees and customers.

Q. Please describe AWEC and CUB's proposal related to the recovery of incentives in the form of stock awards.

A. AWEC proposed the removal of $2,987,990 from PGE's Test Year forecast, which represents the entirety of PGE's stock incentives included in our request. AWEC categorizes this compensation as merely resulting in "dilution of PGE's shareholder equity"[14] rather than a legitimate expense. Furthermore, AWEC posits that stock incentives are "designed to encourage employees to act in the interest of shareholders, as opposed to ratepayers."[15] CUB echoes AWEC's proposal and arguments.

Q. Why does PGE include stock awards in its Total Compensation package for senior leaders?

A. Stock incentives are an important part of PGE's market based competitive Total Compensation package. Stock awards for senior leadership are not just an industry standard, but a standard part of public corporation compensation packages. Were PGE to discontinue this market-standard incentive program we would likely need to increase base salaries to remain competitive in the job market. In short, we include stock awards as a part of our Total

[14] AWEC/100, Mullins/47 at 10-12.
[15] *Id*. at 12-14.

Compensation package because that is what quality candidates across the job market expect and the ability to attract quality candidates to PGE serves customers and shareholders alike.

Q. Parties believe that stock awards incentivize employees to act in the interest of shareholders, how does PGE respond?

A. We reject the idea that the interests of PGE shareholders and our customers are diametrically opposed. A financially sound and efficient utility is in the best interest of both shareholders and customers. As such, providing our senior leaders incentives to act in the long-term interest of PGE provides long-term benefits to our customers that could be lost if PGE replaced these incentives with larger base salaries.

Q. Why does PGE seek recovery for stock-based compensation?

A. Because equity has a fair market value that our employees receive from PGE in the form of compensation. This treatment is consistent with ASC standards, specifically ASC 718-10-25, which states that "[t]he objectives of accounting for equity instruments issued to grantees are to (1) measure the cost of the goods or services received (i.e., compensation cost) [and] (2) recognize that measured compensation cost in the financial statements over the requisite service period."

Q. Please describe AWEC's proposed adjustment related to incentive overheads.

A. AWEC asserts that PGE increased A&G expense by $4,725,343 through the pre-filing adjustment that removes 50% of expense to our allocation credit related to incentive overheads but did not correspondingly reduce the allocated overhead amounts. Based on this premise, AWEC recommends PGE's pre-filing adjustment be reversed.[16]

[16] AWEC/100, Mullins/48.

Q. Is AWECs adjustment reasonable?

A. No. PGE has appropriately made its prefiling adjustment to the entirety of incentive expense amounts. AWEC's adjustment is opportunistically seeking to inflate PGE's 50% prefiling adjustment to non-officer incentives.

Q. Are incentive overhead charges assessed to all other accounts and departments as AWEC asserts?

A. They are for departmental cost tracking purposes. However, for accounting purposes the incentive amounts allocated out to departments are then netted against an equal and offsetting credit within accounting transfer departments. The purpose for this is so managers are able to review their fully loaded departmental budgets, while for accounting purposes, incentive amounts remain in their originating accounts.

Q. Where does PGE ultimately allocate the amounts associated with the credit AWEC identified?

A. The majority of these amounts are allocated to capital projects, with remaining amounts allocated to other balance sheet accounts, co-owners for facilities PGE operates but does not fully own, and below the line activity not included in customer prices.

Q. Does that mean these incentives are not correspondingly reduced as AWEC asserts?

A. No. For amounts capitalized, PGE adheres to the stipulated agreement in UE 283, adopted by Commission Order No. 14-422, which specifies that PGE will not capitalize financial performance-based incentives. As such these amounts already reflect this decision. Additionally, customers do not pay for below-the-line incentive amounts or amounts charged to co-owners.

Q. Please describe CUB's proposal related to the cost-sharing of cash incentives in the 2025 Test Year.

A. CUB notes that PGE includes 50% of all cash incentives in this request, however, they propose that "in recognition that PGE employees have not been properly balancing the interests of customers, PGE should be required to pick up 75% of incentives." CUB proposes that this new cost sharing between PGE and customers last until PGE "can demonstrate that it has taken actions which center the needs of customers." This second proposal results in a proposed $7,134,584 reduction to PGE's Test Year forecast.[17]

Q. How does PGE respond to CUB's second proposed adjustment?

A. As noted in testimony above, shareholders and customers are not diametrically opposed. In fact, PGE would argue that customer and shareholder interests are largely aligned. Customers need and benefit from the assets and infrastructure that PGE is building to maintain a safe reliable grid. Shareholders provide the overnight capital that customers cannot expend up front to make these investments possible and, in turn, they receive a return on their cash invested over time. The financial health of PGE, and the health of our grid that supplies customers with energy are of the upmost importance to shareholders and customers alike, albeit for different reasons. The financial health of PGE positively impacts our dividend and stock price; it also positively impacts PGE's access to lower costs of capital, which reduces customer costs. PGE's 2024 cash incentives targets include metrics for customer engagement, grid readiness, customer satisfaction, and distribution and generation reliability, all of which directly impact our customer's lives – and every PGE employee knows the importance of this and cares very deeply about it.

[17] CUB/100, Jenks/54-55.

Q. How does PGE respond to the general tone of CUB's testimony as it relates to this proposal?

A. PGE finds the multiple stated assumptions of poor intent on PGEs part to be unfounded and without basis. We will continue to seek to engage with all parties in a constructive manner and uphold the integrity of the rate-making process.

Q. Please summarize PGE's stance on Parties' proposed adjustments to Incentives.

A. PGE recommends that the Commission reject all of Parties' proposed adjustments to PGE's 2025 Incentives forecast.

C. Health & Dental Benefits

Q. Please describe the purpose of PGE's Health & Dental benefits program.

A. Health and Dental benefits forecasts are formed in conjunction with our benefits broker's projections for the 2025 year. PGE's main goal in deciding on insurance plans, providers, and cost sharing amounts is to approximate the average of our sector's benefits package as a means maintaining a competitive Total Compensation package relative to the job market. This assists PGE's efforts to attract and retain quality candidates who are best suited to serve our customers.

Q. Please summarize Staff's testimony and proposed adjustments related to Health & Dental benefits.

A. Staff's analysis cites two separate health insurance industry publications: PricewaterhouseCoopers Health Research Institute, and Peterson-KFF. Staff elects to utilize an escalation rate of 6% on PGE's 2024 Health and Dental benefits budget, which approximates an average of the cited publications projections for the 2024 calendar year. This results in a downward adjustment of $1,964,800.[18]

Q. Does PGE have any concerns with Staff's application of these sources?

A. Yes. The PricewaterhouseCoopers article that Staff provides does not directly address the 2024 year, as it is centered around the 2025 year and notes an 8.0% projection in 2025.[19] Meanwhile, the Peterson-KFF article doesn't provide a 2025 projection. More importantly, the Peterson-KFF is not the source of the 5% growth in price that Staff uses to construct their average of 6%. Rather, it cites the federal Centers for Medicare & Medicaid Services annual study, which projects a 5.6% increase in *medical expenditure* in 2024, however, it projects that *health insurance* spending is expected to grow by 8.1% in 2024.[20]

Q. PGE's 2025 Test Year was forecast at the end of 2023, long before premiums would be set. Have there been any updates?

A. Yes. Further communication with Mercer, our Health and Dental insurance brokers has resulted in a revised and near final escalation of approximately 8.5% for health insurance. PGE notes that our original request included a total increase of 9.4% from 2024 to 2025, inclusive of changes in premiums as well as utilization.

Q. Please summarize PGE's position on Staff's proposed adjustment to Health & Dental benefits.

A. PGE recommends that the Commission reject Staff's proposed adjustment to Health & Dental benefits in favor of PGE's original 2025 Test Year forecast. These benefits are an important

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[18] Staff/1100, Peterson/19-20 at 7-6.
[19] "Medical cost trend: Behind the numbers 2025" PWC https://www.pwc.com/us/en/industries/health-industries/library/behind-the-numbers.html, accessed 7/29/2024.
[20] "National Health Expenditure Projections 2023-2032" https://www.cms.gov/files/document/nhe-projections-forecast-summary.pdf, accessed 7/29/2024.

part of a competitive Total Compensation package that serves our customers through the attraction and retention of qualified candidates.

IV. IT Capital Additions

Q. Please describe Staff's testimony and proposed adjustments relating to IT Capital Additions.

A. Staff's analysis looked at the two different categories of IT capital projects: blanket funds and individual projects. Staff proposed adjustments to two of PGE's blanket projects; Network Fitness, which funds the replacement and decommissioning of network infrastructure, and Desktop Fitness, which funds the replacement of desktop and laptop computers as well as peripheral devices such as conferencing technology. For individual projects, Staff did not propose any direct adjustments. However, Staff does propose that both the Zero Trust project and the EMS Upgrade project be subject to officer attestation including the project completion date, actual project cost, and a positive affirmation of an in-service date on or prior to December 31, 2024. Additionally, Staff proposed that their inclusion in rate base be limited to the lesser of the actual costs or the original forecasted amounts.[21]

Q. Please describe Staff's proposed adjustments to the Network and CTO Desktop Fitness projects.

A. Staff proposed a total adjustment of approximately $3.7 million for these two projects. Staff derived this adjustment comparing PGE's estimated closings to the average 2021-2023 historical in-service amounts associated with these blanket projects.

Q. Is simply relying on a three-year average appropriate for forecasting these capital costs?

A. No. A simple three-year average does not factor in the type of replacements, nor does it account for any historical deviations or impacts to these on-going projects. Staff's simple three-year average does not even account for inflation.

[21] Staff/800, Ball/21-22.

Q. What does the Network Fitness blanket project cover and why is spending higher for 2024?

A. Network Fitness is hardware and software that supports the accessibility, stability, and security of PGE's networks. Funds associated with this project support both the replacement of the many different types of network hardware <u>and</u> the expansion of new capabilities. In fact, approximately $2.2 million of the Network Fitness fund is allocated to incremental needs such as purchasing firewall devices and other critical network infrastructure. For example, in 2024 PGE will add nine incremental physical firewalls at a cost of approximately $100 thousand each, before installation and loading expenses. This project not only supports PGE's utility functions, but also represents a large portion of PGE's cyber security efforts that are imperative to PGE's mission to provide secure and reliable energy to our customers.

Q. Why is the CTO Desktop Fitness blanket fund increasing in 2024 compared to Staff's three-year average?

A. The increase in spending for 2024 is primarily due to a delay in spending during 2023. That is, PGE elected to delay the purchase of new engineering computers for one year, which led to lower-than-normal expenditures for 2023. As these computers are now one-year past their expected retirement it is critical that PGE replace them in 2024.

Q. Please respond to Staff's proposal related to the Zero Trust and EMS Upgrade projects.

A. Staff's proposals to the Zero Trust and EMS Upgrade projects relating to attestations and limiting recovery to PGE's initial forecast are addressed in Section XIII of PGE's Exhibit 1300.

Q. Please summarize PGE's stance on Staff's IT Capital Addition related proposals and adjustments.

A. PGE requests the Commission reject Staff's proposed adjustments related to IT blanket funds. Funding for these projects is critical to provide the necessary tools PGE and employees need to effectively operate. Staff's simple three-year average lacks the full context of cost increases and changes in purchasing needs from year to year.

V. Corporate Support

A. Miscellaneous A&G

Q. What proposed adjustments does Staff make to PGE's 2025 A&G Test Year forecast?

A. Staff proposes a reduction of $1.78 million. They support this proposal by providing analysis of the five-year trend of the various FERC accounts associated with A&G. Staff's proposal is specific to FERC account 921, Office Supplies and they conclude that PGE had not supported the proposed increase of 12.5% from 2023 actuals. [22]

Other analysis noted a 26% decrease in FERC account 922 from 2023 actuals, and it was noted that Staff reviewed accounts 923, 930, 931, and 935 but is not proposing any adjustments. Additionally, Staff notes that due to "outstanding data requests" they continue to analyze FERC account 920 and have not reached a conclusion on that account at this time.[23]

Q. What support did PGE provided for the increase to FERC 921?

A. PGE provided support to Staff through Data Request No. 478, and Staff accurately reports the information that PGE provided. However, it should be noted that Staff did not simply ask why FERC 921 increased 12.5% within that data request. Instead, they asked very specific questions about certain amounts in the account. There were no follow-up data requests from Staff or additional questions to better understand the change.

PGE notes that the single largest driver and incremental expense related to this increase is $0.75 million to support training and organizational change management for several of PGE's new software solutions (i.e. Maximo, IQGeo, and C2M). Implementing new software

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[22] Staff/1100, Peterson/17 at 1-6.
[23] *Id*. 16 at 3-7.

requires training and outside support to ensure our workforce is best equipped to take advantage of expanded capabilities and realize the full potential of these solutions.

Q. Does PGE have any other concerns related to Staff's testimony?

A. Yes. Regarding FERC Account 920 Staff noted that they had "outstanding data requests regarding this account" and suggested that analysis was ongoing.[24] Staff pointed to the data request in question, OPUC Data Request No. 602. However, PGE's response to OPUC Data Request No. 602 was electronically delivered to Staff on June 25, 2024, approximately three weeks before Staff filed their opening testimony. Staff's testimony states that they are reserving the right to visit this topic at a later time in this proceeding given the outstanding request, but since we have confirmed that the information was received with plenty of time to address any issues in their opening testimony and have not received any additional discovery on the topic, any belated new issues on this topic would be inappropriate and untimely.

Q. Please describe AWEC's testimony and proposed adjustments to PGE's 2025 A&G Test Year forecast.

A. AWEC proposes a reduction of $4,585,715 to PGE's 2025 A&G Test Year forecast. Their analysis notes that PGE's non-labor O&M expenses have increased, but claim that the way PGE presented this information made it "not possible to perform a detailed variance analysis," pointing to PGE's inclusion of ratemaking adjustments in the Test Year while other years were presented as actuals.[25] The proposed reduction represents two years of escalation to PGE's 2023 actuals, utilizing the Federal Reserve's FOMC forecast for 2024 and 2025, 2.6% and 2.3% respectively. Additionally, AWEC proposes that all of Directors and Officers stock compensation be removed from this case and that PGE split the remainder of Directors

[24] Staff/1100, Peterson/16 at 3-7.
[25] AWEC/100 Mullins/35 at 11-19.

and Officers expense with customers, with PGE paying for 90% of the category. AWEC proposes these adjustments because they assert that "directors' activities are predominantly for the benefit of shareholders," while repeating their arguments against stock incentives and the claim that stock-based compensation incentivizes shareholder-centric decisions.[26]

Q. Did PGE provide 2023 O&M actuals for AWEC to perform an analysis of non-labor A&G?

A. Yes. As part of PGE's initial February filing in this case, PGE provided work paper support for all A&G costs, which included full accounting string level detail of 2021-2023 actuals, PGE's 2024 budget, and the 2025 Test Year. While PGE agrees that the initial response to AWEC Data Request No. 005 inadvertently contained incorrect information, it is unclear why AWEC did not simply refer to PGE's initially filed work paper for this information. Asserting that PGE's increase for A&G is unsupported despite PGE providing this information at the outset of the case does not warrant or support AWEC's proposed reductions.

Q. AWEC's proposed adjustment is based upon escalated 2023 actuals. Is this appropriate?

A. No. Commission Order No. 23-482 in UE 416 established customer prices for 2024. As a party and signatory to applicable settlement agreements in UE 416, AWEC is aware of the amounts approved for recovery in 2024. By asking PGE to use 2023 as the basis for rate making in this case, instead of 2024 amounts already established through a rate making process, AWEC is relitigating 2024 and the results of UE 416. And, as already noted elsewhere, they do so without considering PGE's actual regulated earnings in 2023.

[26] AWEC/100, Mullins/45 at 11-19.

Q. How does PGE respond to AWEC's proposals related to D&O expense, including stock compensation?

A. Adequate and competitive compensation, including stock compensation, is necessary to attract qualified board members. It is important to have a Board of Directors that is highly qualified to perform the duties of the role. Board members bring customer value through oversight and governance, strategic direction, and their wealth of expertise and experience that they bring to decision making. By allowing PGE the opportunity attract and retain a highly qualified and proficient Board of Directors, which we have accomplished, PGE's D&O expense provides clear benefits to customers.

Q. Does PGE have any additional concerns relating to AWEC's testimony and proposed adjustments?

A. Yes. AWEC proposes an adjustment to A&G based upon the overarching trend within this category, while also proposing adjustments to individual components of PGE's A&G Test Year forecast (i.e. D&O expense); together, these adjustments are inappropriately duplicative.

Q. What does PGE request of the Commission regarding AWEC's and Staff's proposed adjustments.

A. We request that the Commission reject both Parties' adjustments to A&G and AWEC's proposed reduction to D&O expense. PGE supported changes to costs within FERC Account 921 nullifying Staff's proposal, and AWEC failed to provide relevant analysis to support their proposal. Further AWEC's D&O proposal is based on flawed logic and is duplicative to their other proposed reductions.

B. Insurance

Q. Please describe PGE's insurance programs.

A. In general, the insurance coverage maintained by PGE falls into two broad programs: Property and Casualty. Our Casualty program includes General Liability and Auto, Workers' Compensation, Cyber Liability, and Directors and Officers (D&O) Liability plans. Through these two programs, PGE maintains a prudent portfolio of insurance coverage consistent with industry peers. In addition to using insurance to manage risk, PGE also continues to evaluate other alternatives as a means of reducing its overall cost of risk.

Q. How do customers benefit from PGE's insurance policies?

A. PGE's insurance policies provide stability in times of emergency. If there was a large liability claim or large asset loss at PGE that was not covered as a part of an insurance policy, the costs of responding to such an event could be considerably higher than the cost of insurance. Moreover, PGE could suffer financially, thereby increasing the cost of capital as our stock price decreases and the cost of borrowing goes up, in turn creating long-term effects on customer rates. A financially stable and healthy PGE is in the best interest of all stakeholders, including customers, and a robust portfolio of insurance policies allows PGE to prepare for circumstances that could harm customers in the near- and long-term.

Q. What areas of insurance does Staff propose adjustments to?

A. Staff proposes adjustments to PGE's property insurance, general & auto liability insurance, workers' compensation insurance, cyber liability insurance, and D&O insurance, as well as a proposed adjustment related to rebates and credits that PGE receives as a part of our insurance programs.

Q. Please describe Staff's testimony and proposed reduction to PGE's 2025 Test Year Property Insurance forecast.

A. Staff proposes a downward adjustment of $2,149,000 to PGE's property insurance expense, citing lower than expected 2024 premiums, while also objecting to PGE's use of any escalation rate due to our transition to a post-loss model. Staff additionally noted that they are "exploring other potential adjustments" related to property insurance, citing the dividend policy of our main property plan provider, Everen.[27]

Q. Does PGE agree that it is reasonable to disallow an escalation rate for property insurance because of PGE's participation in a post-loss plan?

A. No. Post loss insurance, while providing greater stability, still experiences many of the same pressures that commercial insurance does. Generally speaking, as goes inflation, so goes the value of the property being insured—and along with that, the costs of repairs to the property. Therefore, future losses that PGE and other Everen member s will cover through the five-year amortization schedule should have an escalation rate on that basis alone. Additionally, as Staff is aware, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of forecasted premiums related to excess property coverage and our deductible buy-down program remain in the secondary insurance market and are therefore fully exposed to commercial insurance market pricing.

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[27] Staff/800, Ball/8 at 8-19.

Q. How does PGE respond to Staff's exploration of other potential adjustments relating to Everen?

A. PGE objects to Staff's suggestion that new proposals could be recommended in future testimony. At this point in the proceeding, Staff has had ample time to determine if they believe proposing adjustment would be appropriate as PGE originally filed our opening testimony and account level detail of both historical and proposed expenses on February 29th of this year. Allowing for the inclusion of additional adjustments at a later point in this rate case would not permit PGE an adequate amount of time to respond to such proposals.

Q. Please describe Staff's testimony and proposed adjustment to PGE's 2025 General and Auto Liability insurance Test Year forecast.

A. Staff proposes a $4,637,841 reduction in PGE's General and Auto Liability expense. They base this adjustment on lower-than-expected 2024 actual premiums, and reject PGE's growth rate for this expense, replacing it with a rate supplied in a MarketScout report.

Q. What reasoning does Staff apply when rejecting PGE's rate of escalation of this expense?

A. PGE cited wildfire as one of the main drivers of our liability insurance expense, and while Staff agreed that the factors provided did impact insurance rates, they believe that these factors were all accounted for in our 2024 renewal and that no additional consideration is needed for 2025.[28]

Q. What growth rate does Staff propose PGE utilize for General and Auto Liability?

A. Staff proposes we utilize a growth rate of 3.25% from 2024 actual premiums to determine our 2025 forecast. They take this rate from MarketScout's Q1 quarterly report.

[28] Staff/800, Ball/9 at 7-18.

Q. Is this proposal actually supported by the MarketScout quarterly report?

A. No. The MarketScout quarterly report that Staff references has several problems. First, this report does not directly relate to the utility industry. This is significant, because the utility industry has a specific and unique risk profile not captured in this report, and factors such as wildfire liability, discussed in detail below, are drivers that are changing the entire market of liability insurance in this sector. Secondly, the MarketScout report shows a backwards looking examination of the first quarter (Q1) of 2024 and provides no forward-looking projections for the remainder of 2024 or the 2025 Test Year. This means that the 3.25% growth rate in general liability appears to point only to Q1 rates, meaning that there are still nine months of growth unaccounted for in just the 2024 year. Finally, Staff takes the Q1 2024 growth rate of general liability and applies that to all of general and auto liability; however, the MarketScout report clearly notes a projected increase in commercial auto liability expense of 6.7%, and even that only accounts for rate increases in Q1 of this year.[29]

Q. Are there factors other than sector wide losses related to wildfire that would support PGE's forecasted 22% growth in General and Auto Liability?

A. The largest concern currently facing liability insurance for utilities is availability of insurance. The insurance market is not inexhaustible, as both insurance and re-insurance companies set limits to the amount of assets they are willing to cover. Of the upmost concern right now for PGE is our ability to procure liability insurance for the 2025 year, as some insurers are no longer underwriting policies for wildfire coverage, while others have already stated that they are limiting their capacity.

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[29] Exhibit 1403, Staff's Response to PGE Data Request No. 008.

Q. What has PGE experienced in terms of premium rate increases in excess liability and wildfire coverage?

A. Our largest increases in our Casualty program come from excess liability and wildfire coverage. From 2023 to 2024 PGE experienced a 122% increase in excess liability and wildfire coverage. Thus, when compared to the 122% increase in 2023 to 2024 actual premiums, coupled with the limited supply of coverage we will likely face for 2025, a minimum 14% projected increase from 2024 to 2025 is in fact conservative.

Q. Please describe Staff's testimony and proposed adjustment to PGE's 2025 Workers' Compensation forecast.

A. Staff proposes that PGE use our 2023 Workers' Compensation insurance costs as the baseline for this expense, with no growth rate applied, resulting in a proposed reduction of $259,032. The reasoning Staff cites is that the factors included in our 2025 forecast such as rising medical costs, inflation, wage growth, an aging workforce, and increasing in-person work "will likely impact the workers' compensation rate," however, they note their belief that these factors will have no impact on rates in the 2024 or 2025 years.[30] Additionally, Staff states they base their amount on the 2023 premium because PGE had not provided the actual 2024 premium, and we had "indicated that this information will not be available until after July 1, 2024."[31]

Q. How does PGE respond to Staff's testimony and proposed adjustment?

A. Staff's testimony acknowledges the very real growth factors that PGE faces but disagrees that they will have any material effect on workers' compensation premiums. PGE strongly disagrees. The increase in these expenses must logically increase the amounts spent to care for and compensate PGE's workforce in times of need. To suggest that increased medical

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[30] Staff/800, Ball/11 at 1-10.
[31] Staff/800, Ball/12 at 3-5.

costs, inflation, and wage growth will not increase the expense of compensating employees for medical care and lost wages does not logically follow. Staff's analysis also fails to take into account another important factor: the growth of PGE's workforce. PGE has a forecasted growth of 5% in our full-time workforce from 2023-2025, which should result in a proportionate increase to this expense.

Q. Has Staff been provided 2024 Workers' Compensation renewal amounts?

A. Yes. While Staff's reason for not including PGE's 2024 Workers' Compensation premiums in their analysis was due to known amounts not being available until July 1, 2024, their opening testimony was not filed until July 15, 2024. In fact, PGE provided Staff with our 2024 Workers' Comp renewal expense on July 5, 2024 (ten days prior to the filing of their testimony) in response to OPUC Data Request No. 607 and reported the premium to be $557,980. This represents a 7.1% increase from the 2023 premium, which does not support Staff's assertions that Workers' Compensation expense should stay flat.

Q. Please describe Staff's testimony and proposed adjustment to PGE's 2025 Cyber Liability Test Year forecast.

A. Staff proposes to use PGE's 2023 Cyber Liability insurance premiums as a baseline, and to apply a 7.0% annual growth rate for forecasting Cyber Liability insurance for the 2025 Test Year, creating a downward adjustment of $227,876. Staff's reasoning for this adjustment recognizes the increased value of assets in the energy and utility sector that are a driving factor for these insurance rates; however, they believe that our forecasted growth rate of 19.7% is unwarranted with what is known today. The 7.0% rate that Staff proposes comes from the same MarketScout quarterly report as the General and Auto Liability growth rate.

Q. How does PGE respond to Staff's testimony and proposed adjustment?

A. Just as with General & Auto liability above, the 7.0% growth rate referenced in the MarketScout quarterly report is a backwards look at only three months of insurance rates. If this trend continues, then Cyber Liability will increase by far more in 2024 than the 19.7% rate that PGE forecasted.

Q. Please describe Staff's proposed adjustment to D&O insurance for the 2025 Test Year forecast.

A. Staff notes that PGE has already removed 50% of our D&O insurance expense, as per Commission policy. However, Staff recommends a further adjustment, stating that the forecasted 21% increase over 2023 is high and lacks justification.[32] Staff takes the average of the last three years of actuals (2021-2023) and proposes PGE use 50% of that amount as a proxy for a Test Year forecast. This results in a proposed reduction of $219,473.

Q. How does PGE respond to the testimony and proposed reduction of the 2025 D&O insurance Test Year forecast.

A. PGE notes during the years Staff takes their average, 2021-2023, D&O coverage increased 17.5%, which translates to an annualized increase of 5.8%. Applying that annual increase to PGE's 2023 premium produces a figure of $1,854,076. PGE notes that the Test Year forecast of $2,067,000 is informed by the market-based factors that our insurance broker applied to aide us in reaching our original forecast.

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[32] Staff/1200, Yamada/Page 21 at 2-13.

Q. Please summarize Staff's proposed adjustment related to insurance rebates and credits.

A. Staff proposes a downward adjustment of $482,020 related to rebates and credits that PGE may receive as a part of our insurance programs. Staff determined this adjustment by taking the average of rebates and credits that PGE received over the 2021-2023 years and using that figure as a proposed adjustment.

Q. Is this a reasonable adjustment?

A. No. These rebates and credits are not reliable and may not be paid to PGE in any given year. For example, PGE will not be receiving a rebate from Energy Insurance Mutual Limited (EIM).

Q. Please summarize PGE's position on Staff's proposed adjustments to PGE's 2025 Insurance Test Year forecast.

A. PGE recommends the Commission reject Staff's proposed adjustments and upholds PGE's original 2025 Test Year forecast. PGE's insurance expense reflects a prudent measure to protect customers from near-term and long-term instability and financial impacts. PGE has provided clear documentation to support the unavoidable increases in these expenses.

C. Memberships

Q. Why does PGE seek recovery for membership fees and how do these memberships benefit customers?

A. PGE's membership fees are paid to a wide variety of organizations, ranging from independent system operators (ISOs) to professional development organizations, trade groups, industry associations, and more. PGE request recovery for these membership fees because they relate directly to our utility business, benefitting customers in many ways. Examples of these benefits include: a more educated and skilled workforce, access to critical industry research that is only available to members, and required or preferred memberships and certifications that allow certain PGE professionals to practice their trades. Active engagement in organizations that use a membership model also provides access to an expanded network of skilled professionals for shared learning, adopting best practices, and benchmarking performance against industry standards. This promotes a culture of continuous improvement and innovation in service to customers.

Q. Please summarize Staff's testimony and proposed adjustments to PGE's 2025 forecast membership expenses.

A. Staff proposes to adjust PGE's membership dues and expense by $301,984. They reach this adjustment by subtracting $295,484 related to 2023 actual membership expenses that stem from "trade organizations, economic development and civic organizations, unidentifiable acronyms, or insufficient descriptions," and then escalating that figure by an inflation factor of 2.2%.[33]

Q. How does PGE respond to this proposed adjustment?

A. Upon review, PGE found that $47,347 of this adjustment is appropriate. However, the remainder of the expense in this category directly supports our utility business and benefits our customers in various ways, including knowledge access and transfer, collaborative industry wide forums, continuing education and certification of individuals, and access to certain conferences. The supported memberships included in Staff's adjustment can be seen in PGE Exhibit 1404, separated into three categories: trade organizations, HR & DEI initiatives, and continuing education and certification.

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[33] Staff/2100, Rossow/6-7.

Q. What support does Staff offer of Commission policy to disallow these expenses?

A. Staff points to three Commission orders that support these adjustments: Commission Order Nos. 87-406, 91-186, and 09-020. PGE has reviewed these orders and notes that Order No. 87-406 at the pages that Staff referenced, 40-41, contains the Commissions 37-year-old policy relating to "community affairs expenditures" in a UT docket. Commission Order No. 91-186 at the page that Staff referenced, 16, is a stipulation that lacks Commission policy or opinions. Finally, in Commission Order No. 09-020 at the pages Staff referenced, 20-21, the Commission acknowledges their position on "charities, community affairs, and economic development organizations." However, none of these referenced orders mention trade organizations.

Q. What type of membership makes up the largest amount of Staff's proposed adjustment?

A. Trade organizations account for $ 220,868 of Staff's adjustment, more than two-thirds of the total.

Q. What trade organization is the largest recipient of funds related to Staff's proposed adjustment?

A. Eddison Energy Institute (EEI), which accounts for $178,209 of Staff's proposed adjustment.

Q. Does EEI perform any lobbying on behalf of its membership?

A. Yes. However, each year EEI provides a percentage of membership dues that are spent on lobbying and each year PGE performs an adjustment to ensure that customers do not pay for this expense. That is, these amounts are recorded and budgeted "below the line."

Q. How does PGE's EEI membership and participation benefit customers?

A. EEI's core budget (i.e. non-lobbying related expenses, the only portion of dues PGE seeks recovery for) is dedicated to supporting its members' ability to provide affordable, reliable, and resilient clean energy to their customers. This goal is accomplished through pooling the collective resources of their members to support the research and dissemination of knowledge that drives PGE's decision-making process during this pivotal and challenging time in the utility industry. More than two-thirds of EEI's core budget is allocated to issues related to generation, transmission, and distribution of electricity, as well as solutions for the end-user, while the remaining third is largely dedicated to supporting the understanding of the best practices of administrative and financial decisions. In short, EEI supports PGE's abilities to make the best and most informed decisions possible to serve our customers.

Q. Does Staff's proposed adjustment include any amounts related to other trade organizations?

A. Yes. In addition to PGE's EEI membership, Staff proposes an additional $42,659 dollars of trade organization dues be removed from the 2025 Test Year.

Q. Are these memberships in the customers' interest?

A. Yes. All of these memberships have one overarching theme: they help PGE improve processes, compliance, and decision making. This goal is accomplished through their dedicated expert staff that follow a wide variety of issues and help determine best practices. This is accomplished by providing a forum for collective problem-solving, or through commissioning studies and research to determine best practices, or all of the above and more. Trade organizations provide all of these benefits at an extraordinary value to their members because the pooled resources of the membership efficiently leverages limited resources to accomplish a wider range of important tasks with efficiency. For example, Pacific Northwest Utilities Conference Committee (PNUCC) provides insights and forums for discussion on the toughest problems facing the ever-transforming utility industry. Without pooled resources to fund research, and forums to gather diverse viewpoints from a variety of industry experts, PGE would face today's industry-specific issues largely in a bubble alone. In contrast, as a part of a group we can leverage the combined resources of the members to be stronger, faster and smarter for our customers.

Q. Please describe the non-trade organization membership expense that Staff proposed to adjust.

A. PGE continues to support memberships in two categories other than trade organizations: HR & DEI initiatives, and continued education and certifications. HR serves the heart of any company, and PGE's HR department works tirelessly to supply PGE with a qualified and diverse workforce, to develop employee relations best practices and policies, and to ensure compliance with the myriad local, state, and federal laws and regulations. Such an integral, multi-faceted role requires expert input and ongoing education. For that reason, PGE supports HR memberships as prudent utility industry expenses that benefit customers through the functioning workforce they support. Additionally, ongoing education and certification supports the continued development, growth, and capacity of our personnel, which allows us to serve customers better. Exhibit 1404 provides further details regarding both of these membership categories.

Q. Please summarize PGE's response to Staff's proposed adjustment to the memberships Test Year forecast.

A. While PGE recognizes that $47,347 was mistakenly included in the 2023 memberships actuals, the remainder of these expenses are prudently incurred as part of continuous business and staff improvement and to the benefit of our customers. PGE therefore recommends the Commission reject the remaining portion of Staff's proposed adjustment. Staff's assertion that trade organizations offer disproportionate support to PGE at the expense of customers is unfounded, as is their assertion of Commission policy relating to recovery of these expenses.

D. Meals and Entertainment

Q. Please describe Staff's proposed adjustment to PGE's 2025 Meals and Entertainment forecast.

A. Staff proposes a downward adjustment of $142,608. This adjustment is calculated by the subtraction of expenses related to specific transactions within the meals and entertainment calculation as well as some expenses related to awards, recognition, and miscellaneous discretionary costs that were unintentionally omitted from our meals and entertainment adjustment.

Q. How does PGE respond to Staff's testimony and proposed adjustments.

A. PGE accepts this downward adjustment of $142,608.

E. Revolver Fees, Margin Net Interest, & Broker Fees

Q. When did PGE start including revolver fees, margin net interest, and broker fees within A&G?

A. PGE first included revolver fees, margin net interest and broker fees in A&G in its 2011 GRC (Docket UE 215), as a result of the stipulated agreement between Staff, the Oregon Citizens' Utility Board, and the Industrial Customers of Northwest Utilities (AWEC's predecessor), that was formally adopted through Commission Order No. 10-410. PGE has since continued to include these costs in A&G in each of its subsequent GRCs.[34]

[34] Docket Nos. UE 262, UE 283, UE 294, UE 319, UE 335, UE 394, UE 416, and UE 435.

Q. Why did PGE begin including these costs within base customer prices?

A. The inclusion of these costs was and is a direct result of PGE's participation in the wholesale power markets.[35] The power markets had evolved over time from bilateral physical trades between and among electric utilities (a predominantly physical market without independent parties) to one that incorporates a number of independent parties and is predominantly financial. While this evolution brought benefits such as more counterparties and additional liquidity, it also brought with it more explicit fees (e.g., revolver fees, margin net interest and broker fees). In summary, these are standard costs incurred through the course of transacting in power markets that PGE has included in each of its previous eight GRCs.

<u>1. Revolver Fees</u>

Q. Please describe AWEC's argument and adjustment associated with revolver fees.

A. AWEC argues that PGE's revenue requirement does not consider the benefits associated with revolver fees and that revolver fees are not considered in PGE's results of operations.[36] Following these assertions, AWEC recommends that the revolver fees "are best addressed in the context of the rate on AFUDC"[37] and should be removed from PGE's revenue requirement.

Q. Do you agree with AWEC's assessment and recommendation?

A. No. Revolver fees are appropriately included in PGE's revenue requirement, pursuant to a stipulated agreement adopted as part of Commission Order No. 10-410 and, contrary to AWEC's assertion, are included within PGE's results of operations reporting.

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[35] As we discuss below, some of these costs are no longer solely associated with wholesale power markets.
[36] AWEC/100, Mullins/42-43.
[37] *Id*. 43, at 5-6.

Q. What is a revolving credit facility and how does it work?

A. A revolving credit facility is a reserve of cash set aside by multiple banks for potential use by a company, usually at times when cash is inaccessible through other channels. The revolver term is the amount of time that a company has secured access to the reserve. Five years is commonly the period secured by utilities and is the term used by PGE. Each year PGE must extend its revolver one more year in order to maintain the five-year period with all of its banks. Should PGE need cash during this time, it can borrow it under the facility. However, if PGE borrows funds under its revolving credit facility, interest would be paid on the amount borrowed at a rate as determined by the revolver agreement with its banks. Typically, this interest rate is much higher than the rate PGE would incur from borrowing cash from other sources, which is why the revolving credit facility is only used as a last resort for meeting liquidity needs.

Q. What are revolver fees?

A. Revolver fees are paid by PGE to the various banks participating in PGE's revolving credit facility for PGE to have access to the cash reserve if needed. Revolver fees include revolver extension fees, annual fees, and agent and legal fees. They do not include any interest on cash borrowed under the facility.

Q. Why is it important for PGE to have access to a revolving line of credit, for which PGE pays revolver fees and how does this benefit customers?

A. There are two key reasons that a revolving credit facility is necessary and beneficial to customers. First, a revolving credit facility gives PGE immediate access to capital when all other possibilities are inaccessible. For example, when debt markets were constrained due to the COVID-19 pandemic, PGE was able to use its revolving credit facility to access cash when there was a short-term liquidity shortage in the market. This directly benefits customers by ensuring PGE always has access to enough liquidity to meet collateral requirements for power operations, to meet PGE's load serving obligations as efficiently as possible, and to maintain its business.

Second, rating agencies (in PGE's case, Standard & Poor's and Moody's) take PGE's ability to access this revolving credit facility into consideration when determining credit ratings, which includes associated fees (e.g., revolver fees). Without such access, PGE could lose its investment-grade rating. Such an outcome would impede PGE's ability to offer and sell debt or equity securities quickly to take advantage of favorable market conditions and would increase capital costs to the detriment of customers.

Q. Is it appropriate to address revolver fees within the context of AFUDC, as AWEC suggests?

A. No. These fees provide PGE access to a line of credit and are not the actual interest paid on this credit when utilized. Any actual debt and interest from this facility, just like any other types of short-term debt, is not included in PGE's revenue requirement. However, the access is long-term in nature.

Q. What is PGE's recommendation regarding revolver fees?

A. We recommend that revolver fees continue to be included within PGE's revenue requirement as forecast. These fees, which allow PGE long-term access to a revolving line of credit, directly benefit customers and are appropriately included within PGE's revenue requirement and results of operations, consistent with Commission Order No. 10-410.

2. Margin Net Interest

Q. What is Margin Net Interest?

A. Margin net interest is interest paid by PGE to trading counterparties for deposits that are held as collateral for energy, capacity, transmission, and fuel purchase contracts, which are critical for PGE in securing economic and reliable power to meet customer load. PGE posts or receives collateral deposits (also known as margin deposits) related to wholesale power and fuel contracts where delivery and/or settlement occurs in the future. PGE holds deposits made by counterparties with which PGE transacts (e.g., utilities, power marketers, and clearing brokers). These deposits are based on the difference in the contract price relative to the current market price, and in the case of deposits held by a clearing broker may also include a maintenance component.

Q. Please summarize AWEC's proposal regarding Margin Net Interest.

A. AWEC recommends removing the margin net interest from PGE's revenue requirement, arguing that PGE receives a cash benefit from these deposits, which is not considered as an offset to rate base. Because of this, AWEC claims it is inappropriate to include the interest cost.

Q. Does PGE receive a cash benefit from these deposits?

A. No. These amounts, which PGE briefly holds for energy, capacity, transmission, and fuel purchase contracts, must be readily available to pay back. That is, PGE must maintain immediate liquidity of amounts and cannot use these funds for any other purpose.

Q. What is PGE's recommendation regarding margin net interest?

A. As the corresponding "financing benefit" that AWEC bases their recommendation on simply does not exist, we recommend PGE's net margin interest forecast be maintained, consistent with Commission Order No. 10-410.

3. Broker Fees

Q. Please summarize AWEC's adjustment to broker fees.

A. AWEC recommends that broker fees be removed from PGE's revenue requirement based on their understanding that such fees are related to the issuance of equity and debt.

Q. What are the broker fees included within PGE's administrative and general costs associated with?

A. These are fees PGE pays to third-party brokers for arranging or locating trades for PGE's power operations organization as well as fees from clearing brokers and exchanges that facilitate trades of energy, capacity, transmission, and fuel-related commodities.

Q. What is the significance of broker fees to PGE?

A. Broker fees are essential for the operation and maintenance of the trading platform, ensuring that traders have access to secure and efficient markets. This helps to keep PGE's costs low for gas and electricity. Additionally, broker fees may also include costs for clearing services, which provide stability and risk management across global markets.

Q. What is your response to AWEC regarding broker fees?

A. AWEC does not recognize the importance of trading platforms and clearing brokers in mitigating risks and costs of trading. Trading platforms provide an efficient and accessible way to execute trades in various financial markets. With a trading platform, PGE has access to real-time market data, controls over trading tenors, and greater access to markets.

Since counterparty names are not displayed, trades are based on price only. These allow PGE to make trades based on lowest prices. Having the deals cleared also mitigates the risk of default. By having trades executed on a trading platform and cleared, PGE keeps the cost of hedging deals low.

Q. Are broker fees in any way related to the issuance of equity and debt as AWEC states?

A. No. As such, we recommend no change to these costs as included in PGE's revenue requirement. Broker fees are appropriately forecasted and included consistent with Commission Order No. 10-410 and benefit customers by helping to lower PGE's net variable power costs while continuing to meet customer's energy demands.

VI. Qualifications

Q. Ryan Van Oostrum, please summarize your qualifications.

A. I graduated from George Fox University with a Bachelor of Arts in Accountancy, majoring in Accounting and Finance. From 2008 to 2015, I was employed by PricewaterhouseCoopers LLP, working in the assurance practice with a focus on the power and utilities industry and obtained my Certified Public Accountant (CPA) qualification. Since joining PGE in 2016, I have held several managerial positions with responsibilities over SEC and FERC financial reporting, Asset Accounting, Corporate Accounting and Gross Margin Accounting. I became the Controller in July of 2023, and in this role I oversee PGE’s daily accounting operations, accounts payable and receivable, and payroll teams. I have 16 years of experience in accounting matters in the power and utilities industry.

List of Exhibits

PGE Exhibit	Description
1401	Contract Labor Adjustment Calculation
1402	Incentives Worksheet
1403	Staff's Response to PGE Data Request No. 008
1404	Memberships Worksheet

Account: Capital or Operating of Account	CE Source	Sum of 2021 Budget	Sum of 2022 Budget	Sum of 2023 Budget
Capital: Capital	1101: Straight-Time Labor - Salary	9164382.73	12173990.01	14700385.33
Capital: Capital	1102: Straight-Time Labor - Union	23583303.04	25068218.19	22899867.37
Capital: Capital	1103: Straight-Time Labor - Hourly	592169.71	579789.1	1251203.59
Capital: Capital	1200: Other Union Labor	1056699.06	1778879.51	1465706.16
Capital: Capital	1201: Union High Time	0	0	0
Capital: Capital	1202: Union Premium Pay	0	0	0
Capital: Capital	1401: Overtime - Hourly	9850.79	34813.29	0
Capital: Capital	1402: Overtime - Union	4857872.46	7891836.15	4607794.4
Capital: Capital	1501: Temporary Labor Straight Time	13491.31	10052.55	-725589.27
Capital: Capital	1502: Non-PGE Labor Straight Time	-738594.04	17102355.44	19397697.73
Capital: Capital	1601: Temporary Labor Overtime	0	0	0
Capital: Capital	1602: Non-PGE Labor Overtime	1739177.96	2518111.24	225168.53
Capital: Capital	5104: Vacation OH	16128827.22	17840780.38	20034909.47
Capital: Capital	5501: Labor Allocation - ST Salary	48109415.67	57692410.47	61663357.35
Capital: Capital	5502: Labor Allocation-ST Hrly Union	5771342.51	5550597.56	7581312.18
Capital: Capital	5503: Labor Allocation-ST Hrly NonUn	2633577.33	2776320.52	3637861.45
Capital: Capital	5505: Labor Allocation-Union Premium	0	0	12325.81
Capital: Capital	5506: Labor Allocation - Hourly OT	98428.4	115217.99	101951.77
Capital: Capital	5507: Labor Allocation-Union HrlyOT	643636.19	682124.24	799967.57
Capital: Capital	5509: Labor Allocation-ST Temporary	147649.07	63995.08	249809.71
Operating: Operating	1101: Straight-Time Labor - Salary	164206507.5	198828996.2	191603418.3
Operating: Operating	1102: Straight-Time Labor - Union	37991636.88	39934188.73	45848867.41
Operating: Operating	1103: Straight-Time Labor - Hourly	20918447.14	20282585.36	19630174.73
Operating: Operating	1200: Other Union Labor	1651390.93	2056816.41	2679579.36
Operating: Operating	1201: Union High Time	0	0	500
Operating: Operating	1202: Union Premium Pay	0	0	97000
Operating: Operating	1401: Overtime - Hourly	1239169.86	1309827.57	1038801.19
Operating: Operating	1402: Overtime - Union	9875014.71	11423439.55	13438082.06
Operating: Operating	1501: Temporary Labor Straight Time	2731053.81	1452101.14	2341141.98
Operating: Operating	1502: Non-PGE Labor Straight Time	13915652.91	529047.33	13377005.48
Operating: Operating	1601: Temporary Labor Overtime	26008.33	73271.83	2198.55

Operating: Operating	1602: Non-PGE Labor Overtime	265022	2769807.3	4046961
Operating: Operating	5104: Vacation OH	29837737.97	32737629.51	32944159.15
Operating: Operating	5501: Labor Allocation - ST Salary	-48814284	-58649478.48	-62274918.34
Operating: Operating	5502: Labor Allocation-ST Hrly Union	-5494841.65	-5334474.64	-7425736.94
Operating: Operating	5503: Labor Allocation-ST Hrly NonUn	-2580509.75	-2796114.23	-3653386.3
Operating: Operating	5505: Labor Allocation-Union Premium	0	0	-12325.81
Operating: Operating	5506: Labor Allocation - Hourly OT	-98428.4	-115217.99	-101951.77
Operating: Operating	5507: Labor Allocation-Union HrlyOT	-643896.75	-682238.53	-800268.97
Operating: Operating	5509: Labor Allocation-ST Temporary	-154696.01	-67026.53	-259431.78
Grand Total		338682214.9	395632652.3	410423598.4

Account: Capital or Operating of Account	CE Source	Sum of Dec - 2021	Sum of Dec - 2022	Sum of Dec - 2023
Capital: Capital	1101: Straight-Time Labor - Salary	18744820.79	24172748.92	28914965.4
Capital: Capital	1102: Straight-Time Labor - Union	19925311.39	22441780.75	23160629.14
Capital: Capital	1103: Straight-Time Labor - Hourly	871813.28	1203715.74	1211751.34
Capital: Capital	1200: Other Union Labor	0	0	0
Capital: Capital	1201: Union High Time	30333.13	32161.14	26182.92
Capital: Capital	1202: Union Premium Pay	1883261.15	1901443.39	2087166.49
Capital: Capital	1401: Overtime - Hourly	103914.55	129739.97	156614.23
Capital: Capital	1402: Overtime - Union	8922990.82	9860746.96	10589130.14
Capital: Capital	1501: Temporary Labor Straight Time	136558.76	44732.55	80388.03
Capital: Capital	1502: Non-PGE Labor Straight Time	21567283.72	35722955.27	32638976.18
Capital: Capital	1601: Temporary Labor Overtime	18734.95	142.26	18567.84
Capital: Capital	1602: Non-PGE Labor Overtime	23573583.69	6736345.22	4403229.14
Capital: Capital	5104: Vacation OH	15494685.3	17349125.96	19951402.58
Capital: Capital	5501: Labor Allocation - ST Salary	40526628.86	47022440.53	50367865.88
Capital: Capital	5502: Labor Allocation-ST Hrly Union	4473033.64	3936787.42	4034363.69
Capital: Capital	5503: Labor Allocation-ST Hrly NonUn	2105078.55	2013325.9	2826684.08
Capital: Capital	5505: Labor Allocation-Union Premium	32838.29	65163.93	256501.39
Capital: Capital	5506: Labor Allocation - Hourly OT	26187.91	53878.19	82663.94
Capital: Capital	5507: Labor Allocation-Union HrlyOT	630393.43	544381	1170749.8
Capital: Capital	5509: Labor Allocation-ST Temporary	210000.91	128043.64	160768.08
Operating: Operating	1101: Straight-Time Labor - Salary	155683325	169905005.4	175648512.2
Operating: Operating	1102: Straight-Time Labor - Union	35250148.18	37056958.11	39170287.27
Operating: Operating	1103: Straight-Time Labor - Hourly	16688505.42	16426734.65	16482342.05
Operating: Operating	1200: Other Union Labor	0	0	0
Operating: Operating	1201: Union High Time	20141.02	36112.84	28518.69
Operating: Operating	1202: Union Premium Pay	4009271.08	2878200.69	3475365.58
Operating: Operating	1401: Overtime - Hourly	1660018.01	963036.36	1221727.41
Operating: Operating	1402: Overtime - Union	18051858.95	14175098.87	16431104.65
Operating: Operating	1501: Temporary Labor Straight Time	2630421.58	2877349.52	2403610.98
Operating: Operating	1502: Non-PGE Labor Straight Time	27017435.6	31375313.02	19750024.12
Operating: Operating	1601: Temporary Labor Overtime	128429.24	79279.02	130766.86

Operating: Operating	1602: Non-PGE Labor Overtime	22517261.35	4139083.8	3687740.72
Operating: Operating	5104: Vacation OH	28614415.91	29177198.08	31300449.72
Operating: Operating	5501: Labor Allocation - ST Salary	-41058875.83	-47624835.03	-50795321.57
Operating: Operating	5502: Labor Allocation-ST Hrly Union	-4330592.92	-3859811.38	-3928835.03
Operating: Operating	5503: Labor Allocation-ST Hrly NonUn	-2060591.9	-2034412.38	-2841220.1
Operating: Operating	5505: Labor Allocation-Union Premium	-33826.97	-65236.11	-256828.84
Operating: Operating	5506: Labor Allocation - Hourly OT	-26228.24	-53878.19	-82663.94
Operating: Operating	5507: Labor Allocation-Union HrlyOT	-644273.67	-548737.58	-1176708.45
Operating: Operating	5509: Labor Allocation-ST Temporary	-217442.83	-133902.58	-166374.2
Grand Total		423176852.1	428128215.8	432621098.4

Sum of 2024 Bud	Sum of 2025 GRC
17430930.17	$ 17,293,615.08
25753761.06	$ 29,344,720.99
915549.13	$ 952,171.11
1341923.78	$ 1,418,312.40
0	$ -
0	$ -
0	$ -
6342085.3	$ 6,701,728.76
0	$ -
20036195.62	$ 20,242,568.59
0	$ -
3050816.63	$ 3,082,239.58
21721538.85	$ 22,376,933.08
68002246.1	$ 70,397,248.75
7423794.41	$ 7,784,144.75
3954698.86	$ 4,047,286.02
15395.7	$ 15,889.77
97011.18	$ 98,524.88
1169573.88	$ 1,223,386.89
211031.4	$ 218,939.42
207166963.6	$ 221,168,867.27
48324195.95	$ 51,016,247.36
20646243.6	$ 20,781,552.32
2849950.68	$ 3,010,646.43
0	$ -
120418.32	$ 120,418.32
962428.39	$ 1,083,050.82
13821524.55	$ 14,604,160.80
2304413.6	$ 2,391,671.41
10651705.26	$ 12,884,398.84
2286.51	$ 2,377.98

	2021 Bud vs Act			**2022 Bud vs Act**	
	Capital	O&M	Total	Capital	O&M
Straight-time	$ 3,656,227	$ 7,441,739	$ 11,097,966	$ 3,443,452	$ 24,598,123
OT	$ (4,982,167)	$ (11,116,131)	$ (16,098,298)	$ (2,084,786)	$ (3,397,977)
Non PGE	$ (44,140,283)	$ (35,354,022)	$ (79,494,306)	$ (22,838,834)	$ (32,215,542)
Total	$ (45,466,224)	$ (39,028,413)	$ (84,494,637)	$ (21,480,167)	$ (11,015,397)

	2025 GRC vs 2023 Act		
	Capital	O&M	Total
Straight-time	$ 21,706,241	$ 41,128,007	$ 62,834,248
OT	$ (4,929,734)	$ (2,288,622)	$ (7,218,356)
Non PGE	$ (13,717,397)	$ (6,679,965)	$ (20,397,363)
Total	$ 3,059,110	$ 32,159,420	$ 35,218,529

	2021 Bud vs Act	2022 Bud vs Act
Straight-time	$ 7.4	$ 24.6
OT	$ (11.1)	$ (3.4)
Non PGE	$ (35.4)	$ (32.2)
Total	$ (39.0)	$ (11.0)

3833911.21	$	3,873,400.54
34515775.05	$	36,093,322.35
-68677700.62	$	(71,129,862.67)
-7265804.94	$	(7,617,068.42)
-3981202.46	$	(4,075,878.40)
-15395.7	$	(15,889.77)
-97011.18	$	(98,524.88)
-1169764.65	$	(1,223,579.58)
-219159.93	$	(227,393.11)
441240329.3	$	467,839,627.68

	2023 Bud vs Act			2021-2023 Avg Bud vs Act		
Total	Capital	O&M	Total	Capital	O&M	Total
$ 28,041,575	$ 584,299	$ 11,480,837	$ 12,065,136	$ 2,561,326	$ 14,506,900	$ 17,068,226
$ (5,482,763)	$ (7,399,831)	$ (3,429,667)	$ (10,829,498)	$ (4,822,261)	$ (5,981,258)	$ (10,803,520)
$ (55,054,376)	$ (17,419,339)	$ (6,013,798)	$ (23,433,137)	$ (28,132,819)	$ (24,527,788)	$ (52,660,606)
$ (32,495,564)	$ (24,234,871)	$ 2,037,371	$ (22,197,500)	$ (30,393,754)	$ (16,002,146)	$ (46,395,900)

2023 O&M Bud vs Act	2021-2023 Bud vs Act
$ 11.5	$ 14.5
$ (3.4)	$ (6.0)
$ (6.0)	$ (24.5)
$ 2.0	$ (16.0)

Non-Officer Incentives, as reported in SDR 092

	2021	2022	2023
Incentives	34,119,693	31,782,633	30,941,494
Real Incentives	40380131	34828015	32570873.07

Year	CPI
2022	1.08
2023	1.041
2024	1.03
2025	1.022

Average Incenctives 2021-2023 Inflation Adjusted:	$	35,926,340
Less 50%:	**$**	**17,963,170**

FTEs, as reported in SDR 092

2021	2719
2022	2816
2023	2776

Average FTE 2021-2023:	2770
2025 Forecast FTE:	2903
Delta (%):	4.79%

Average Incentives 2021-2023 Inflation and Population Adjusted:	$	37,646,792
Less 50%:	**$**	**18,823,396**
PGE's 2025 Test Year Forecast:	$	17,936,907

Date: August 2, 2024

TO:
Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC-0306
Portland, OR 97204

FROM: Dustin Ball, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 435 – PGE Data Request No. 8

PGE Data Request No. 8:

Reference Staff's Exhibit 800:

a. What industries are considered in the MarketScout report referenced in Staff's testimony. Does the MarketScout report provide industry specific insurance projections or provide any insight that is specifically relevant to the utility industry?
b. Provide copies in their entirety of all MarketScout reports referenced or relied upon in Staff's testimony.

OPUC Data Response No. 8:

The MarketScout report, does not include a detailed breakout listing all industries considered. However, the report does contain information on premium trends by industry class as shown on page 3 of 4 in Attachment 8-A. The listed industry classes include: Manufacturing, Contracting, Service, Habitational, Public Entity, Transportation, and Energy.

Attachment 8-A provides a copy of the MarketScout report referenced in Staff 800.

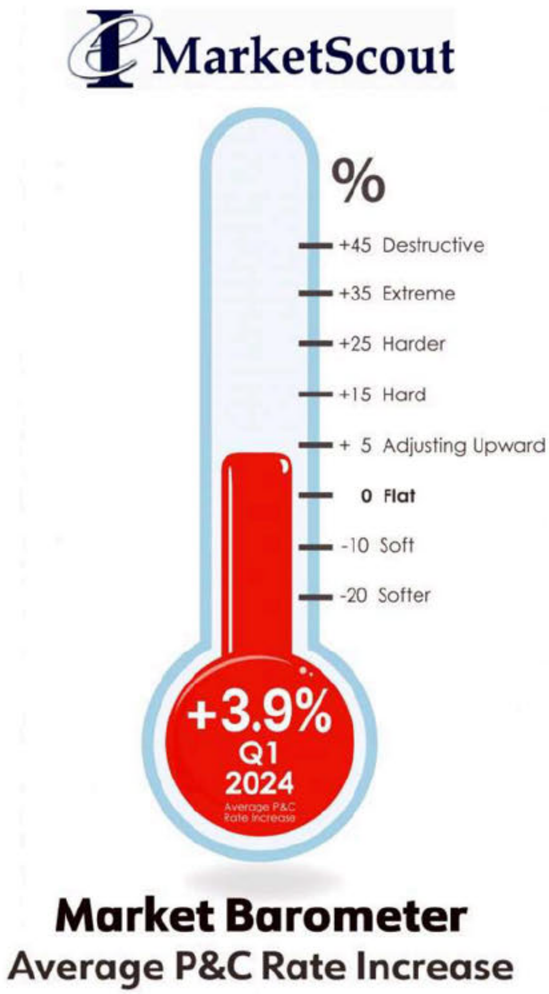
Ball, Dustin Contact Us Portal Access Logout

MarketScout ABOUT US SPECIALTY EXPERTISE MARKETSCOUT EXCHANGE PARTNERSHIPS MARKET

Commercial Rates in US Up 3.9% on all Property and Casualty Placements

Property CAT and pending liability developments still worry insurers

In the United States, the composite rate for commercial insurance in the first quarter of 2024 was up 3.9%, a notable decline from the fourth quarter of 2023, which was plus 5.6%. Richard Kerr, CEO of Novatae Risk Group noted, "January and February posted very modest rate increases; however, rates were trending upward more aggressively in March. Property insurers are nervous about the 2024 catastrophe season. Liability insurers are more calm but economic conditions and incurred, but not yet reported, claim estimates may impact rates later in 2024."



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Auto and property insurance rates remain the highest among all coverages at plus 6.7% and plus 6.3% respectively. By industry group, transportation risks are being assessed with the highest rate increases at plus 6.7%.

The National Alliance for Insurance Education and Research conducted pricing surveys used in MarketScout's analysis of market conditions. These surveys help to further corroborate MarketScout's actual findings, mathematically driven by new and renewal placements across the United States.

A summary of the first quarter 2024 rates by coverage, cyber liability, industry class and account size is set forth below.

By Coverage Class

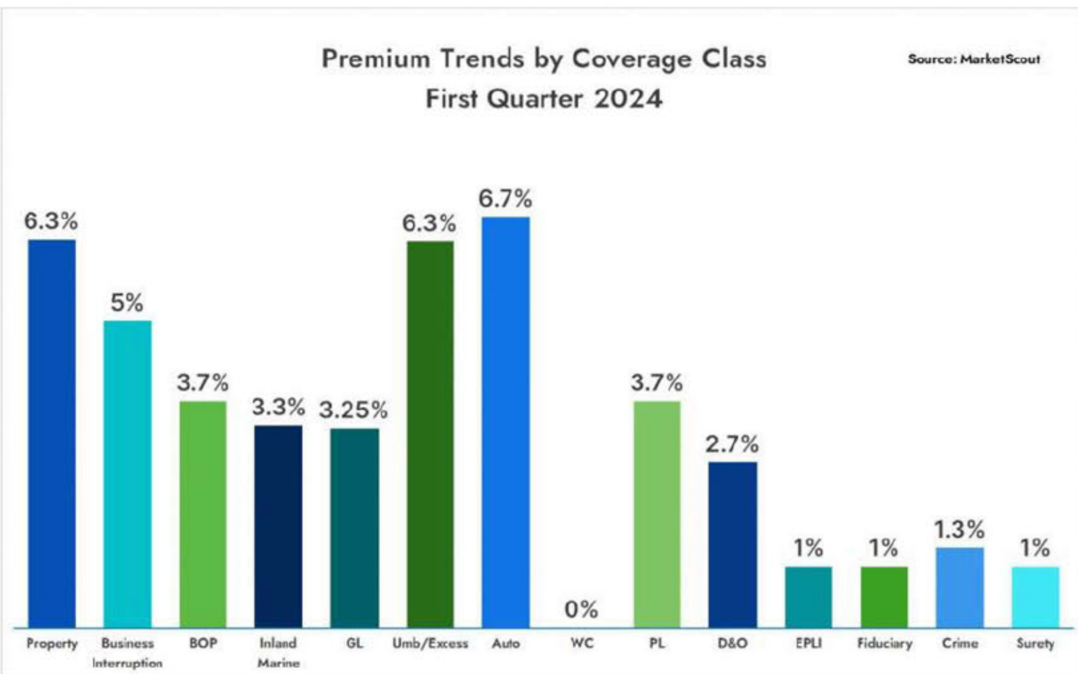
Commercial Property	Up 6.3%
…terruption	Up 5%
BOP	Up 3.7%

MarketScout's Market Barometer is a quarter of the industry's comp rate index for property/casualty and personal insurance. For access to future barometers pricing data please complete the survey.

Take The Market Barometer Survey

For more granular data contact Vilma Scott.
vscott@marketscout.com
Phone #: 972 934 4224

Inland Marine	Up 3.3%
General Liability	Up 3.25%
Umbrella/Excess	Up 6.3%
Commercial Auto	Up 6.7%
Workers' Compensation	Flat 0%
Professional Liability	Up 3.7%
D&O Liability	Up 2.7%
EPLI	Up 1%
Fiduciary	Up 1%
Crime	Up 1.3%
Surety	Up 1%

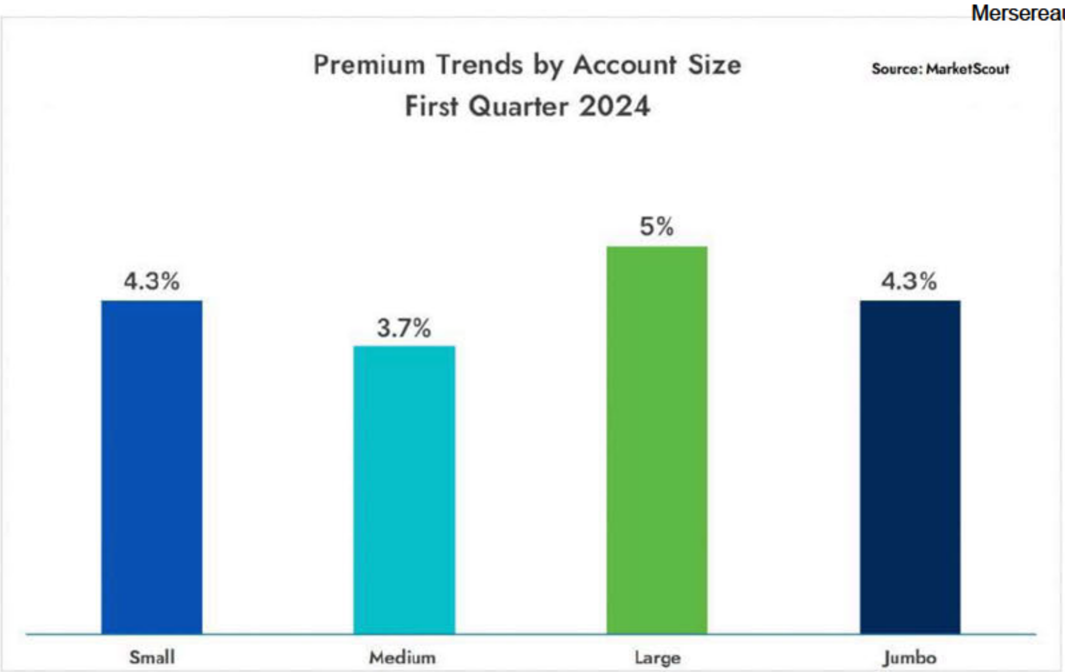


Cyber Liability

Cyber	Up 7%

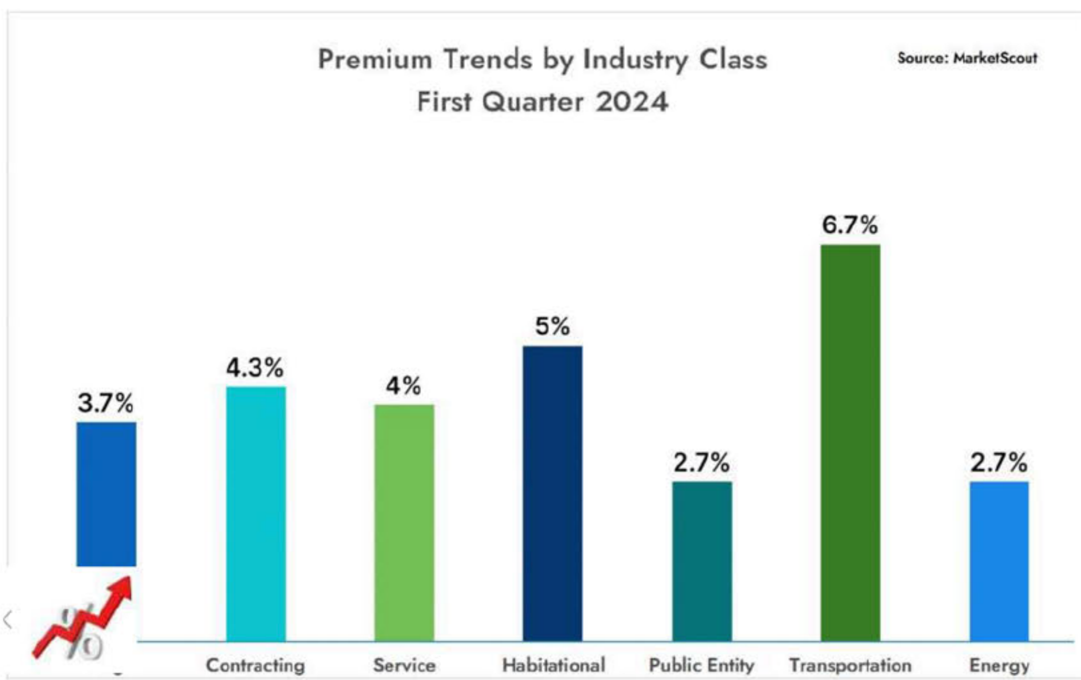
By Account Size

Small Accounts – Up to $25,000	Up 4.3%
Medium Accounts – $25,001 – $250,000	Up 3.7%
Large Accounts – $250,001 – $1 million	Up 5%
ounts – Over $1 million	Up 4.3%



By Industry Class

Manufacturing	Up 3.7%
Contracting	Up 4.3%
Service	Up 4%
Habitational	Up 5%
Public Entity	Up 2.7%
Transportation	Up 6.7%
Energy	Up 2.7%



For detailed rating analysis or market projections by industry class, coverage or account size, contact Vilma Scott at vscott@marketscout.com.

About MarketScout, a Division of Novatae Risk Group

Founded in 2000, **MarketScout, a Division of Novatae Risk Group**, is an insurance distribution and underwriting company headquartered in Dallas, Texas. The company is a Lloyd's Coverholder and MGA for US insurers with specialty expertise in workers' compensation, private client solutions, energy, healthcare, fine art, equine, jewelry, professional liability, and many specialty programs. MarketScout's company culture and sense of community encourages growth, learning and collaboration. The company has been named as one of the Best Places to Work in Insurance by Business Insurance for ten consecutive years. In November 2022, MarketScout joined Novatae Risk Group and Richard Kerr was named the combined companies' CEO. California license #0D60423.

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UE 435

Exhibit 1404 has been retained and provided in its native format

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Customer Service and Transportation Electrification

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

John McFarland
Elyssia Lawrence

August 14, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is John McFarland. I am the Vice President and Chief Commercial and Customer Officer at PGE. My qualifications appear at the end of this testimony.

My name is Elyssia Lawrence. I am the Senior Manager of Product Management for Transportation Electrification at PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony responds to the opening testimony of the Staff of the Public Utility Commission of Oregon (Staff), Alliance of Western Energy Consumers (AWEC), and Walmart (jointly, Parties) on the topics of customer service non-labor Operations and Maintenance (O&M), Transportation Electrification-related O&M expense and Transportation Electrification-related charging infrastructure.

Since we did not write opening testimony in this proceeding—as our 2025 Test Year request is essentially unchanged from the prior general rate case proceeding (Docket No. UE 416)—we will also provide a brief overview of the 2025 Test Year Customer Service and Accounts O&M showing our request is necessary and reasonable in order to provide benefits and quality service for our customers.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II – Overview & Summary
- Section III – Customer Service & Accounts O&M
- Section IV – Department-Specific O&M Issues
- Section V – Transportation Electrification Infrastructure
- Section VI – Qualifications

II. Overview and Summary

Q. Please provide an overview of Parties' Customer Service revenue requirement-related recommendations.[1]

A. Parties' recommendations are summarized by the type of expense as follows:

- **Non-Labor O&M**: Staff and AWEC propose reductions to non-labor O&M in Customer Accounts and Customer Service, with AWEC focused on the Outside Service cost element and Staff focused on FERC Accounts 903[2] and 908.[3]
  - Customer Accounts (FERC Account 902, 903, 905): Staff recommends a \$2.0 million reduction to FERC Account 903[4] and AWEC recommends a \$2.6 million total decrease to Outside Services across these three accounts.[5] Staff also recommends a \$25.5 thousand reduction related to Amazon Pay electronic payment expense.[6]
  - Customer Service (FERC Accounts 908 and 909): Staff recommends a \$2.0 million reduction to FERC Account 908[7] and AWEC recommends a \$5.3 million decrease to Outside Services across both accounts.[8]

Staff and AWEC use slightly different approaches and subsets of data, but the reductions and underlying rationale of relying on 2021-2023 spending levels are the same.

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[1] CUB/100, Jenks/24 recommends a 20% reduction to the billing expense revenue requirement, which is \$8.5 million, at least partially to FERC Account 903, related to PGE's bill. This item is addressed in PGE/1200.
[2] FERC Account 903, is Customer records and collections expense, which includes billing activities.
[3] FERC Account 908, is Customer assistance expenses.
[4] Staff/1100 Peterson/7.
[5] AWEC/100 Mullins/35.
[6] Staff/1800 Shearer/3.
[7] Staff/1100 Peterson/11.
[8] AWEC/100 Mullins/34.

- **Labor O&M:** AWEC proposes a $700 thousand reduction to Key Customer Department Labor O&M.[9] This proposed reduction, however, is duplicative to the overall wage and salary reductions addressed in PGE Exhibit 1400 - Compensation and Support and therefore double counting.
- **Transportation Electrification-Related O&M and Rate Base**: Staff makes several recommendations regarding PGE's transportation electrification (TE) efforts: 1) a reduction to O&M (both labor and non-labor); (2) disallowance of capital for the Transportation Line Extension Allowance (TLEA) program; and (3) disallowance of capital for the following customer public charging infrastructure and support projects - Electric Avenue and TriMet (UM 1811 pilots), Salem Electric Avenue, Electric Island, and the TE Database.[10]

Q. Please summarize PGE's response to these proposals.

A. Parties recommend material reductions to Customer Service and Accounts O&M which, if approved, would have a significant impact on customer-facing service operations and customer program offerings. As we will explain, the 2025 Test Year requests a non-labor O&M total increase of $2.5 million, however, $2.2 million of this increase is related to the incremental Distributed Standby Generation (DSG) amortization. When normalizing for the DSG amortization, non-labor O&M is only a $300 thousand, or 1.47% increase in 2025. Importantly, in order to mitigate O&M customer price pressure, PGE did not make any notable incremental requests in Customer Service and Accounts in this rate review proceeding.

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[9] AWEC/200 Kaufman/3.
[10] Staff/2200 Shierman/24.

PGE requests the Commission approve the 2025 requested Customer Service and Accounts non-labor O&M as filed, which is materially consistent with the prior general rate case.

Upon reviewing final project costs, PGE does agree that a $3,125 reduction to rate base for UM 1811 pilots is appropriate. PGE also agrees to remove $25.5 thousand related to Amazon Pay and will evaluate whether to offer this option to customers in the future.

III. Customer Service and Accounts O&M

Q. Please describe the primary functions of PGE's Customer Service organization.

A. PGE's Customer Service organization is multi-faceted and supports diverse needs across three customer segments: residential, commercial, and industrial. Among a variety of services, our customer teams provide timely and accurate billing, a variety of payment options, start/stop/move service support, large customer new service coordination, enrollment in energy programs, and scalable digital platforms (e.g., website, mobile app). Our customer service teams also closely collaborate with other functions within PGE to respond to outages and provide restoration estimates, align customer projects with PGE's system planning, staff local community resource centers, communicate important updates to customers, and answer customer questions and concerns. Our focus is serving each customer with genuine care, being knowledgeable, and offering right-fit solutions that are delivered directly from the Customer Service organization or in collaboration with other PGE teams.

Q. What improvements were launched this year for improved customer experience?

A. PGE's focus on continuous improvements to our systems, resources, and services to continue to evolve how we engage with customers. Important projects completed this year include: (1) a new dynamic dashboard designed to help customers track and understand their home energy use and offer tools and programs help to manage energy use or save on their bill; (2) an interactive quiz that helps customers decide which energy shifting program is right for them (Peak Time Rebates, Smart Thermostat, Time of Day, or Smart Charging); (3) a new web page dedicated to resources to help customers manage their bill with programs, incentives and rebates, bill assistance and IQBD; and (4) enhanced mobile app performance for connectivity, speed, and reliability.

Our efforts to continuously improve were recently recognized by the 2024 Forrester Customer Experience Survey where PGE's score surpassed the average U.S. Customer Experience Index score, and the company is one of only two utilities that saw an increase in customer experience scores compared to others in the industry. The Forrester Customer Experience Index survey measures customer experience quality in terms of effectiveness, ease, and emotion.[11]

Q. Please summarize PGE's request for 2025 Customer Service and Accounts O&M.

A. As a mitigant to customer price impacts, PGE held its 2025 Customer Service O&M request, inclusive of IT allocations and uncollectible expense, at roughly equal to the 2024 budget level. The requested total in this case is $102.7 million, a $2.6 million increase over the 2024 budget. PGE also held its uncollectible rate at the agreed to value in UE 416 as a further mitigant to customer prices. As such, PGE did not submit Customer Service opening testimony in this proceeding due to the essentially flat nature of Customer Service O&M and no material or notable new requests.

Table 1
Customer Service O&M Expenses ($ Millions)

Category	2022 Actuals	2023 Actuals	2024 Budget	2025 Forecast	(2025-2024) Delta*
Labor	$31.6	$29.5	$36.9	$35.2	-$1.7
Non-Labor	$19.9	$18.3	$23.6	$26.2	$2.5
Subtotal*	$51.6	$47.8	$60.5	$61.4	$0.9
Information Technology Allocation	$28.1	$27.0	$28.8	$29.5	$0.7
Subtotal*	$79.7	$74.8	$89.4	$90.9	$1.6
Uncollectible Expense[12]	$7.0	$4.6	$10.7	$11.7	$1.0
Total Base Business Costs*	$86.7	$79.4	$100.1	$102.7	$2.6

** May not sum due to rounding*

[11] 2024 Forrester Customer Experience Survey, Press Release on June 17, 2024.

[12] 2021 and 2022 uncollectible expense reflect lower amounts due to the COVID-19 deferral, which deferred uncollectible expenses above the previously approved amount in Dockets UE 335 and UE 394. PGE held the uncollectible rate in 2025 unchanged from that agreed on in UE 416.

Q. Why do you compare the 2025 Test Year to the 2024 budget instead of 2023 actuals?

A. The 2024 budget is the more appropriate comparator reflecting the expenses currently in base rates and reflective of necessary operating activities and associated costs. Comparing to 2023 would be repetitious of the testimony and discovery in UE 416.

Q. Please summarize Parties' reductions to Customer Service and Accounts non-labor O&M.

A. Both AWEC and Staff recommend reductions to non-labor O&M for Customer Accounts and Customer Service. The reduction amounts differ slightly in their calculation, but the reasoning provided by AWEC and Staff are fundamentally the same. AWEC and Staff use slightly different subgroups of expenses when calculating and applying their methodology. Staff focuses only on FERC 903, whereas AWEC analyzes expenses by cost type rather than FERC account. Both Staff and AWEC argue that PGE's requested 2025 Test Year O&M is too high relative to 2021 to 2023 levels. Staff recommends reductions characterized as equivalent to the level of spending in 2021 to 2023, while AWEC applies the average growth rate between 2021 and 2023 to escalate to 2025.

Q. Do Parties argue that the spending PGE is seeking is not reasonable or justified for 2025?

A. No. Their rationale for the reductions is based on a growth argument. No non-labor O&M items were specifically identified by the Parties for cuts on prudence or reasonableness grounds. Staff does isolate the reductions for Customer Accounts to FERC Account 903 and for Customer Service to FERC Account 908, while AWEC identifies Outside Services as the category (cost element) of spend causing the increase and therefore where the reduction should occur. These accounts and cost element contain the largest amount of spend for Customer Service non-labor O&M.

Q. Do you have any other response to Staff's recommended adjustment?

A. Yes, as a general response, PGE is concerned with Staff and AWEC's reliance on the use of a historical three-year average in an environment where anomalies diminish its predictive value. A historical three-year average can run counter to the purpose of a forward-looking test year and in this case, the historical three-year average also does not recognize the impact of COVID-19 on customer billing activities during the 2021-to-2023-time horizon, inflation on non-labor expenses, customer expectations with respect to large shifts in technology, and evolving business needs in a rapidly changing environment.

A. Customer Accounts Non-Labor O&M (FERC Accounts 902, 903 and 905)

Q. Staff recommends a $2.0 million reduction[13] and AWEC recommends a $2.6 million reduction to Customer Accounts non-labor O&M. Please summarize the $3.2 million increase in PGE's requested 2025 Customer Accounts non-labor O&M.

A. The 2025 increase over 2024 non-labor budget for Customer Accounts is driven by $2.2 million amortization of incremental DSG, which adds incremental capacity to the system to help maintain energy supply reliability. The remainder of the increase is primarily escalations, notably Customer Contact Operations and payment processing fees. Despite PGE explaining these escalations and the cost drivers in a data requests, Staff instead chose to rely on the less accurate three-year average.[14]

[13] Staff 1800/Shearer/2 recommends a $25.5 thousand reduction and Staff 1100/Peterson/7 recommends a $2.0 million reduction. Both of these reductions are represented herein.

[14] See PGE's response to OPUC Staff DR 377.

Q. Since Staff and AWEC are comparing to 2023, can you summarize the increases requested in UE 416 and reiterate the justification, particularly for outside services?

A. The primary drivers of the 2024 increase is normal cost escalations in the customer service organization and additional customer payment processing fees and related billing expenses. As AWEC notes, an accounting reclassification moved $2.5 million from materials and supplies expense classification to outside services expense beginning in 2024, however, this is accounting "geography" and not a new request.

Q. What is Staff's recommendation regarding Amazon Pay payment processing fees?

A. Staff proposes a $25.5 thousand reduction to the Amazon Pay payment processing fees due to PGE's inability to provide the contract provisions due to non-disclosure agreement.[15]

Q. Please respond to Staff's recommendation on Amazon Pay.

A. PGE views Staff's position as more of a discovery dispute than an issue with providing the Amazon Pay service, as Staff has raised no specific concerns justifying the adjustment amount. Amazon is a digital wallet payment platform offering that gives customers a new method (digital wallet) for payment. Digital wallet or digital payment channels will be an increasingly important offering for our customers as adoption increases and the current Amazon Pay offering allows PGE to pilot the use of these payment channels. That being said, PGE will agree to remove $25.5 thousand from the 2025 O&M request and is evaluating whether this service will be provided to customers in 2025.

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[15] Staff/1800 Shearer/3.

Q. How does PGE respond to Staff and AWEC's proposed reduction to Customer Accounts Non-Labor O&M?

A. We find their proposals do not appropriately align with the minimal increase requested to support necessary activities for PGE to continue to serve its customers in our call centers, billing and payment operations, and field meter services. The DSG amortization is the key driver of the non-labor increase in this area and is a needed capacity resource where PGE can actively partner with our customers.[16]

B. Customer Service Non-Labor O&M (FERC Accounts 908 and 909)

Q. Staff recommends a $2.0 million reduction and AWEC recommends a $5.3 million reduction. Please summarize the $0.3 million decrease in PGE's requested 2025 Customer Service Accounts non-labor O&M.

A. The 2025 decrease over 2024 non-labor budget for Customer Accounts is largely driven by higher 2024 budget for Brand Marketing which represented a one-time movement of dollars from 2023 into 2024 budget to inform customers about how their participation in energy management has an impact on cost, reliability, and sustainability to inspire action. This work was previously known as People Powered Energy. Other changes in Customer Service non-labor O&M are minimal escalation for inflation, offset by the decrease in Brand Marketing.

Q. Since Staff and AWEC are comparing to 2023, can you summarize the increases requested in UE 416 and reiterate the justification, particularly for outside services?

A. Some of the key changes made as part of the 2024 rate review and reflected in 2024 and 2025 Test Year relative to 2023 actuals are: (1) moving energy efficiency funding from Schedule

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[16] Further discussion of the benefits of the incremental DSG can be found in PGE/1700, Powell-Clark/21.

110 into base rates which increased the Energy Efficiency Outreach department budget by $920 thousand; (2) increasing Communications and Outreach by $1.5 million to build awareness about actions customers can take related to energy management; and (3) two years of escalations.

Q. How do customers benefit from the increases in Customer Service O&M from UE 416?

A. Customers benefit in several ways. First, including Schedule 110 Energy Efficiency Customer Service and the TE deferrals in base rates simplifies the number of line items otherwise listed on the customer bill. Second, the customer service organization is at the core of customer offerings and program development. Through the ongoing tracking, reporting and evaluation of customer programs, system value is enhanced and allows for more efficient advancement and increase in the value of customer programs. Third, raising customer awareness of the changing electricity landscape and actions they can take to participate in PGE programs that help them manage usage and support reliability and sustainability. It also provides customers with an overall better awareness of the market and grid changes in the Pacific Northwest as well as available incentives for participation in energy management.

Q. Does Staff identify specific concerns to justify the proposed $2.0 million reduction to Customer Service non-labor O&M?

A. Staff draws incorrect conclusions regarding Customer Service non-labor O&M by relying on Staff testimony in UE 416.[17] Staff claims that PGE's fleet program does not belong in the customer assistance expense FERC Account, however Staff's proposed reduction fails to recognize that the amounts for EV Field Operation department related to PGE's own fleet and

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[17] Staff/1100 Peterson/10 at 10 to Staff'1100 Peterson/11 at line 2.

workplace are no longer budgeted to Customer Service Account 908, so this is not a valid point.

Q. What is your request for the Commission to do concerning Customer Service Non-Labor O&M?

A. We request the Commission deny Staff and AWEC's proposed reductions as their proposals do not appropriately align with the programs and offerings which drive system and individual customer benefit. The 2025 requested non-labor O&M for Customer Service is a small decrease compared to 2024. The increase from 2023 to 2024 budget reflects three major items resolved in UE 416: Moving Schedule 110 Energy Efficiency Customer Service and two TE deferrals into base rates in 2024 and funding for increased communications and outreach. We request the Commission approve the Customer Service non-labor O&M so PGE can continue to provide customers with Key Customer Management, TE programs, and other customer offerings.

IV. Department-Specific O&M Issues

Q. Please summarize the department-specific issues addressed in this section of your testimony.

A. This section of our testimony responds to proposed reductions related to three departments: Key Customer Management, TE, and EV Field Operations.

Specifically, AWEC proposes a reduction to the Key Customer Management team of $700 thousand[18] based on a misunderstanding of the labor cost changes related to the number of positions in the team. AWEC's labor reduction also duplicates AWEC's overall wage and salary reduction, which is addressed in PGE Exhibit 1400.

Staff makes O&M reduction recommendations of $920 thousand in the TE department and $993 thousand in the EV Field Operations team.[19] Because the majority of these costs are labor O&M, it is also a reduction that is duplicative of Staff's wage and salaries reduction.

C. Key Customer Management Department Labor O&M

Q. Please describe the function of the Key Customer Management team.

A. The Key Customer Management team currently consists of 12 Key Customer Managers (KCM), an analyst,[20] a project manager, an operations manager, and a senior manager. This team is responsible for building and maintaining long-term relationships with large customers, supporting their energy needs. KCMs are a large customer's first point of contact and provide a critical customer service by helping to coordinate and implement solutions for complex issues across a variety of areas including but not limited to construction projects,

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[18] AWEC/200, Kaufman/3.
[19] Staff/2200, Shierman /9,16.
[20] This position is budgeted in RC893 and RC563 for 2023 and 2024 and officially moves to the KCM team in 2025. This position does not increase the overall revenue requirement in 2025, but represents the movement of costs from another area of the company.

planned and unplanned outages, billing, contract negotiation and administration, and program enrollment.

Q. How have the service needs of large customers changed in recent years?

A. As the electric industry undergoes significant transformation, large industrial customers, as high energy usage customers, are at the forefront of the change. Key Customer load has grown more than 20% since 2020, and the solutions and programs needed to reliably serve and meet the reliability and decarbonization expectations of these customers are both increasingly more complex and technical.

Q. Do parties address the Key Customer Manager team in opening testimony?

A. Yes. Both AWEC and Walmart specifically address the Key Customer Management department in their testimony. AWEC recommends a reduction of $700 thousand to the requested 2025 Key Customer Management department labor expense.[21] Walmart provides testimony on "the valuable service provided by the Company's key account management team"[22] but does not make a recommendation.

Q. Why does AWEC recommend a reduction to the Key Customer Management O&M budget?

A. AWEC reduces labor O&M due to the consistent KCM headcount between 2023 and the 2025 Test Year; relying on PGE response to AWEC DR 096, which asks PGE to identify the number of KCMs from 2019 to present.[23]

[21] AWEC/200, Kaufman/3-4.
[22] Walmart/100, Perry/26 at 1-2.
[23] AWEC/202, Kaufman/4.

Q. Does AWEC have a valid point on the headcount of this department?

A. No. While the number of KCMs is not forecasted to change, this department has added three support positions in the 2025 Test Year relative to 2023. PGE's response to AWEC 098 (which, unlike PGE's response to AWEC 096, was not included as an exhibit to AWEC's testimony) identifies these three additional positions, which includes moving an existing analyst position to the department.

Q. How will customers benefit from the three positions added in the KCM department?

A. Walmart describes the benefits of a Key Customer Manager, specific to their experience:

> For Walmart, in particular, which generally maintains multiple sites within a utility's service territory, it also ensures a single, consistent messages applicable to all of its operations. A top-notch account representative is practically a member of the customer's energy management team and an advocate for the customer within the utility organization.[24]

Walmart also discusses the benefits to other utility customers and the broader community, through business continuity during storms and emergency events, and the installation of energy equipment such as generators to provide resiliency. PGE will note that large customers enrolled in demand response, DSG, and other customer-sided capacity programs which are increasingly important during winter storms and heat events. KCMs engage customers to enroll in solutions that work for the customer and can provide system benefit to all customers.

Q. What is your request for the Key Customer Management Department Labor O&M?

A. We request the Commission deny AWEC's recommended $700 thousand reduction in the Key Customer Management department labor O&M recognizing that the three incremental positions are necessary to provide customer service support in light of the increasingly complex and transformative environment, enhance the quality of service for customers, and

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[24] Walmart/100, Perry/24 at 16-20.

reduce the need to add Key Customer Manager positions noting that one of the three positions is a transfer with no net increase cost in the 2025 request.

D. Transportation Electrification O&M

Q. Please describe the purpose and background behind the creation of PGE's TE department?

A. PGE's TE department develops and deploys the programs, tariffs, partnerships, and infrastructure required to equitably support the use of electricity as a transportation fuel. PGE is guided in these efforts by House Bill 2165,[25] Executive Order (EO) 20-04, and Senate Bill (SB) 1044,[26] along with the earlier guidance of EO 17-21 and SB 1547.[27] Taken together, these legislative and governor actions spanning the last nine years represent a state policy to expedite transportation electrification in Oregon. These policies and other state actions set robust goals for zero-emission vehicle adoption in Oregon and recognize a vital role for utilities to analyze infrastructure needs, support the built environment for electric vehicles, monitor grid impacts, and provide programs and incentives to help address barriers to equitable adoption to advance customers' goals for EV adoption.

Q. Please summarize Staff's recommendation regarding PGE's Customer TE department.

A. Staff recommends an O&M reduction of $920 thousand for the TE department, which would effectively be all labor O&M.

Q. What is Staff's rationale for their recommended TE Department-related O&M adjustment?

A. Staff's primary rationale to adjust the TE department O&M budget from $2.6 million to $1.7 million is based on the incorrect assumption that PGE's 2025 Test Year TE-related O&M must be limited to the O&M in PGE's approved TE Plan.

[25] Oregon House Bill 2165 passed in 2021.
[26] Oregon Senate Bill 1044 passed in 2019.
[27] Oregon Senate Bill 1547 passed in 2015.

Q. What are the factors impacting PGE's overall 2025 TE forecast?

A. The TE ecosystem is still maturing and evolving. In this context, product planning, development, and implementation require dedicated PGE time and expertise, including leadership and support for meaningful associated regulatory and stakeholder engagement processes. The resources needed for this core planning and development are not appropriate to include in the TE Plan, where the TE Plan is focused on the customer program and activity-specific budgets to deliver those programs to customers, not overall resource costs to plan, develop, and administer. Establishing and maintaining a sufficient workforce to support and advance product planning and portfolio development continues to be an important consideration, especially given the ongoing nature of the work and its essential integration into PGE's core business. PGE must be prepared to plan for TE load, serve TE load, and manage TE load while supporting our customers' transition to electrified transportation across all use cases. The TE department must also be equipped and prepared to provide robust reporting and analytics Staff and stakeholders expect to ensure an understanding of our activities and value they bring to customers.

PGE expects electric vehicle adoption in our service area to grow significantly from 53,939 in 2023 to over 90,525 by the end of 2025, and to continue to an estimated 418,000 electric vehicles by the end of 2030.[28] This is a 68% growth rate by the end of 2025 and 608% by 2030.[29] Maintaining the requested funding for the TE Department and EV Field Operations Department will ensure continued equitable access to electricity as a transportation fuel for

[28] *In the Matter of Portland General Electric Company 2019 Transportation Electrification Plan*, UM 2033, Table 11 of PGE's Transportation Electrification Plan (August 25, 2023).
[29] May 2024 PGE EV forecast using AdopDER with a baseline of 53,939 EVs at the end of 2023.

these vehicles – and to plan for and serve this growing load as electric vehicle adoption continues to increase.

Q. Please elaborate further on the core planning and product development activities performed by this department that are not reflected in the TE Plan.

A. Examples of the current planning and product development activities performed by the TE department include:

- Tracking of the TE market space and technology evolution.
- Forward-looking program changes for managed changing, future rates and rate design to optimally plan for new load and serve different TE charging uses.
- Development of low-income, renter, and multi-family charging strategy and future offerings.
- Creation of PGE's TE Plan and evaluation of PGE's overall TE portfolio.
- Integration of TE-specific needs into the overall base utility processes and operations.

Q. How does Staff calculate the TE-related O&M adjustment?

A. Staff draws upon PGE's filed TE Plan, which shows a total of $1.7 million[30] of O&M expense in base rates for customer programs. Staff takes the TE department total budget of $2.66 million and allows for the $1.7 million, resulting in the $920 thousand reduction.

Q. How does PGE respond to Staff's approach and adjustment?

A. Staff's recommendation to reduce PGE's 2025 TE-related O&M to that of the TE Plan omits the broad and necessary functions of the TE department as described above. The TE Plan displays the customer program funding by source, not the totality of the resources necessary

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[30] Staff/2200, Shierman/9.

to develop, monitor, and administer these programs and assess and monitor an evolving market. Staff's recommendation would significantly limit PGE's capacity to develop, implement and report on the comprehensive utility TE Plan mandated by statute and the Commission's Division 87 rules. PGE would struggle to execute its 2023-2025 TE Plan, achieve and report on the performance metrics outlined in Staff's UM 2165 investigation, develop the next TE Plan, and support the state's zero-emission vehicle goals established in SB 1044. Staff's approach also neglects to differentiate the O&M in the TE Plan with the EV Field Operations department, which is tasked with the ongoing maintenance for Fleet Partner, Electric Avenues, and TriMet.

Q. Does PGE agree that the 2025 Test Year forecast should be aligned with the recently filed TE plan?

A. Partially. We agree as relates to the customer program-related components of the test year that are included in the TE Plan. However, as we stated above, not all department-related O&M costs are included in the TE Plan, nor should they be included in the TE Plan. For example, components of PGE's request relate to expenses for development, administration, EV field operations, and other base business activities that are not included in the TE Plan, just as other base business activities are not necessarily included in budgets for other specific program areas.

Q. What is your recommendation regarding PGE's requested TE department O&M request?

A. PGE respectfully requests the Commission approve the requested Transportation Electrification department budget of $2.7 million. This request ensures PGE can continue TE program development, development of the next TE Plan, and administration to support transportation electrification for our customers and execute on the customer transportation electrification programs in the TE Plan.

E. EV Field Operations Department

Q. Please provide a brief overview of PGE's EV Field Operations department and justify the requested funding for this department.

A. The purpose of the EV Field Operations department is to consolidate and expand PGE's expertise in the installation and maintenance of charging infrastructure. Established in late 2022, this department supports PGE's customer programs such as Fleet Partner and Electric Avenue as well as PGE's own fleet electrification and workplace charging. Its primary goal is to assist customers in their transition to electric transportation by providing public, fleet, and heavy-duty charging infrastructure.

Although the department is focused on capital projects in the near-term, there are expenses that cannot be capitalized but are necessary to support its operations. The O&M requested in this rate case is for two purposes: the first is for the maintenance of PGE's Fleet Partner, TriMet and Electric Avenue customer programs a portion of which were previously in deferrals but were brought into base rates in 2024. Secondly, approximately 40% of the O&M for this department is used to maintain PGE fleet and workplace chargers, which supports the goal of the department to ensure that PGE's field staff are trained and equipped to operate and maintain a rapidly growing charging infrastructure portfolio. These roles play a crucial role in supporting customers during their transition to electric transportation, ensuring compliance with interconnection and operational standards, and enabling flex load capabilities.

PGE's proposed budget includes formal training by charging infrastructure equipment manufacturers for field staff. This training empowers PGE to perform repairs on its own equipment, leading to more timely repairs, safeguarding the electric power system, and reducing costs for PGE's customers. Furthermore, it enhances PGE's ability to educate customers and assist them in lowering their transportation electrification costs. The forecast also accounts for specialized tools and test equipment to ensure the safe operation and performance of all electrical equipment before it is used by employees and/or the public. Additionally, PGE is creating a spare parts inventory to mitigate supply chain challenges and prevent delays in acquiring necessary parts as charging manufacturers continue to mature their products.[31]

Overall, the EV Field Operations department budget is approximately 60% for the purpose of supporting customer programs and chargers and 40% for maintaining PGE's fleet and workplace chargers at PGE facilities.

Q. Please explain how PGE's EV Field Operations department supports PGE's fleet electrification efforts.

A. PGE's EV Field Operations department supports PGE's fleet electrification efforts in several ways. First, PGE's investment in electrifying our fleet aligns with the state's greenhouse gas (GHG) reduction goals, as established in EO 20-04, which sets "science-based GHG reduction goals."[32] Furthermore, the executive order directs the Commission to encourage "electric companies to support TE infrastructure that supports GHG reductions, helps achieve the TE

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[31] For example, PGE was recently quoted a 42-week lead time for a direct current fast charging unit.
[32] Executive Order 20-04, Oregon Office of the Governor (Mar. 10, 2020) at 5, eo_20-04.pdf (oregon.gov).

goals outlined in SB 1044, and is reasonably expected to result in long-term benefit to customers."[33]

In addition to EO 20-04,[34] PGE's fleet electrification efforts also align with state goals described in Oregon Department of Environmental Quality's (DEQ) Advanced Clean Trucks rule[35] and the Advanced Clean Cars II rule that will require all auto manufacturers to deliver 100% new zero-emissions battery electric and plug-in hybrid vehicles by 2035.[36] By investing in fleet electrification and related infrastructure, PGE is preparing for this market shift and demonstrating prudent planning in accordance with these policies.

Moreover, PGE's fleet electrification initiatives provide valuable experience and insights that enhance our ability to support customers in their own fleet electrification endeavors. The knowledge gained from electrifying PGE's fleet enables the Company to offer guidance, expertise, and practical assistance to customers as they navigate their own transition to electric transportation.

Q. What is Staff's proposed adjustment to the EV Field Operations O&M?

A. Staff proposes a reduction of $993 thousand, which would eliminate the entire budget of the EV Field Operations department.[37] Staff's reduction is based on the view that all TE-related O&M, must be in the TE Plan to be approved for base rates. Staff also mistakenly assumes the TE Plan O&M is for the TE Department and does not allow for the customer-program-related budget in EV Field Operations. Lastly, Staff's adjustment based on the 2023 TE Plan fails to account for what was identified as deferral O&M of $306 thousand in the TE Plan,

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[33] *Id*. at 8, section B.(2).
[34] *Id*.
[35] OAR Ch. 340 Div. 257, for additional information see Department of Environmental Quality : Clean Truck Rules 2021 : Rulemaking at DEQ : State of Oregon (oregon.gov/deq)
[36] OAR Ch. 340 Div. 257, for additional information see Department of Environmental Quality : Advanced Clean Cars II : Rulemaking at DEQ : State of Oregon (oregon.gov/deq)
[37] Staff/2200 Shierman/16.

which has since been included in base rates.

Staff also mistakenly argues that EV Field Operations for PGE's fleet are budgeted to FERC Account 908—a customer service-related account, however, this is an old argument from Docket No. UE 416.[38] PGE's fleet activities are budgeted to A&G, Account 935, for PGE Facilities.

Q. How does PGE respond to Staff's elimination of the budget for the EV Field Operations department?

A. The EV Field Operations department is designed to support both PGE's own fleet electrification and customer programs. The O&M budget in the Test Year will be utilized for PGE customer program maintenance, including the activities moved from deferrals into base rates, PGE's own fleet and workplace maintenance, and for training services to enhance staff expertise.

Q. What would be the impact on approved TE-related programs and PGE's ability to meet statutory requirements in support of TE if the Commission approves Staff's recommendation to remove $993 thousand in O&M expense from PGE's request?

A. Staff's recommendation would severely limit PGE's efforts to develop an EV Field Operations department for charging installation and maintenance would be significantly hampered. The reduced funding would impact PGE's ability to provide staff training on charging infrastructure installation and maintenance, as well as limit their capacity to acquire the necessary tools and spare parts for timely and cost-effective maintenance.

[38] Staff/1100 Peterson/10.

Q. What is your recommendation regarding PGE's requested EV Field Operations O&M?

A. PGE respectfully requests the Commission approve the EV Field Operations department budget of $993 thousand. This request ensures PGE can continue to develop internal expertise for charging equipment installation and maintenance to support the growing number of electric vehicle chargers in our service territory and maintain performance of existing sites.

V. Transportation Electrification Charging Infrastructure

Q. Please summarize Staff's TE Infrastructure recommendations.

A. Staff makes several recommendations for permanent disallowance of TE-related infrastructure. These are investments Staff has recommended for disallowance in past rate cases and notes that these have been settled in past stipulations.

Despite the origins and benefits of these projects having been discussed in multiple prior proceedings, Staff repeats its arguments here for projects that are serving customers and providing benefits which we will discuss. For example, Staff requests permanent disallowance of the Salem Electric Avenue chargers despite Staff acknowledging these chargers had to be removed to accommodate the Oregon State Capital construction project.[39] This is not imprudence on the part of PGE, and PGE has worked with Staff consistently through the years to demonstrate customer use and benefits from the TE investments.

F. Transportation Line Extension Rate Base

Q. Please summarize Staff's Transportation Line Extension Rate Base recommendation.

A. Staff recommends the Commission permanently remove $1.1 million[40] from rate base for line extension allowances it deems imprudent due to what Staff refers to as "unreasonably optimistic site load forecasts."[41]

[39] Staff Report for October 17, 2023 Public Meeting UM 2033, page 3. Also in Appendix A of Commission Order No. 23-380.

[40] Staff states two different numbers in testimony related to 2024 for removal from rate base, we assume that the 2024 number is $176 thousand as appears in Staff's workpapers.

[41] Staff/2200 Shierman/18.

Q. Please summarize Staff's concerns with PGE's calculation of TE-related Line Extension Allowances (LEA) and their proposed adjustments.

A. Staff is concerned with the capacity factor, also known as the combined factor (CF) that PGE utilizes in our LEA calculations for EV infrastructure. Staff performed alternative calculations of PGE's LEAs based on a capacity factor of 0.04 and proposed what they believed the LEA should have been based on this capacity factor.

Q. Why were PGE's calculated LEAs appropriate?

A. PGE's calculated LEAs in previous years were deemed suitable because they were aligned with our business practices at the time. Prior to 2023, it was not PGE's practice to separate EV charging load from the rest of the building load. Consequently, when a site was developed that included EV charging facilities the load was calculated based on building type, making the application of a capacity factor unique to EVs unsuitable. Further, in their calculations of disallowances, Staff does not consider the actual job cost where the job cost is lower than the calculated LEA. If the actual job is completed for less than the calculated LEA, only the job cost has been included for cost recovery. By not considering actual job cost that is less than the LEA, Staff is overstating their proposed disallowance for amounts not even being requested for recovery. Additionally, there was at least one LEA that Staff examined that was related to more than just TE load and Staff's proposed disallowance would ensure that the customer did not receive the line extension allowance they are entitled to for the non-TE load.

Q. Why is Staff's broad use of a CF of 0.04 inappropriate?

A. Staff's use of 0.04 CF in all LEAs is inappropriate because it fails to consider that the CF of TE-related load can vary depending on the type of site. Beginning in 2023, PGE began using a CF of 0.04 to calculate the LEA for all EV sites unless PGE was aware of information that would cause us to revise that CF. In 2024, based on data shared with Staff, PGE updated and began delineating the CF for EV sites based on the type of site, utilizing a CF of 0.05 for private EV sites and 0.14 for public EV sites. The usage at privately available charging will vary from the usage at a public charging site, which warrants a different CF. Further, it is PGE's standard practice to substitute an alternative CF based on historical usage or a number of other site-specific factors that may supersede the standard CF used in the absence of this information.

Q. Has PGE changed its methodology for calculating LEAs for loads related to EVs or TE?

A. Yes. As EVs become more common in PGE's service territory and the availability of data to calculate EV-related CFs is more readily available on a historical basis, PGE does consider EVs separately from other load at the site. Before 2023, PGE did not consider EV load separately from building load.

Q. Why didn't PGE revise existing LEAs based on these new practices?

A. PGE is contractually obligated to provide the customer with the lesser of the calculated LEA or the job cost if the customer moves forward with construction within six months of the signed LEA. It would be a poor business practice and an extremely negative customer experience to change the LEA calculation based on new methodology when the customer is in the middle of construction, and it would violate the signed agreement.

Q. What does PGE propose the Commission do?

A. We request that the Commission reject Staff's proposed LEA adjustments for the reasons outlined above and allow $1.1 million in LEA capital expenditures in rate base as they were prudent and reasonably calculated based on the information available at the time.

G. UM 1811 TriMet and Electric Avenue Pilots

Q. Please summarize Staff's recommendation regarding the UM 1811 pilots.

A. Staff recommends a permanent rate base disallowance of $367 thousand[42] reflecting the amount of project cost Staff believes is above the maximum allowable overnight capital costs established by Commission Order 19-385 (Docket UM 1811).[43] Staff previously noted that these pilots were prudent projects, except for the portion Staff believes is over the maximum allowable limit.[44]

Q. Does PGE change the amount for which it is seeking recovery of in response to Staff's recommendation for these pilots?

A. Yes. While we do not agree with Staff's calculation or Staff's definition of overnight capital and application of the cap to indirect costs, we agree to the reduction to the TriMet pilot rate base of $3,519 dollars. The amount of rate base reduction is based on findings from further review and calculation where the amount related to outside service costs associated with the installation of the chargers and decals is above the cap. This review identified that the chargers and charging instructions provided at the Sunset Transit Center exceeded the maximum allowable costs for overnight capital. However, the actual overage only amounts to $3,519. We agree TriMet pilot rate base should be reduced by $3,519 dollars and will explain below why a reduction of $367 thousand is inappropriate.

Q. Please describe what costs the Commission included within "maximum allowable costs" in Order No. 19-385.

A. Commission Order No. 19-385, paragraph 10 states:

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[42] Staff/2200 Shierman/4 and Staff Exhibit 2402.
[43] *In the Matter of Portland General Electric Company Application for Transportation Electrification Programs*, Order No. 19-385, Appendix A at 4 (Mar 10, 2020).
[44] UE 416, Staff/1700 Shierman/11.

> Maximum allowable costs are composed of direct O&M costs and overnight capital costs from the pilot. Indirect costs such as interest on expenses and capital carrying costs (e.g., interest during the construction period, property taxes, income taxes, salvage, return requirements) related to the overnight capital costs, franchise fees, OPUC fees, and uncollectibles are not included in the maximum allowable costs.[45]

A footnote to this section of the order goes further to explain "The Stipulating Parties acknowledge that de minimis 'indirect' costs like those described in paragraph 10 have not been included in the maximum allowable cost caps … due to the difficulty in calculating them at this point in time."[46]

Q. How does PGE define "overnight capital costs" as specified in Order 19-385?

A. We define overnight capital costs as the direct, incurred, capital costs of projects. In PGE's response to UE 416 OPUC Data Request No. 746, we provided detailed pilot spend with specific cost elements. The direct, incurred, capital costs of these projects sum to $3.018 million, which is below the established maximum allowable costs of $3.025 million in Commission Order No. 19-385.

Q. Please describe what PGE considers indirect capital costs associated with the TriMet and Electric Avenue Network Pilots.

A. We define indirect costs as those representing overhead and allocated costs, which include labor loadings, AFDC, payroll taxes, and rents. Table 2 below displays the project cost by direct/incurred cost, loadings and allocations, and AFDC.

Q. What are loadings and allocations and why does PGE add them to capital projects?

A. Labor loadings represent labor-related costs such as employee benefits, pension costs, incentives, payroll taxes, employee support, paid time off, and where applicable, injuries and

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[45] *In the Matter of Portland General Electric Company Application for Transportation Electrification Programs*, Order No. 19-385, Appendix A at 4 (Mar 10, 2020).
[46] *Id*.

damages. Other indirect costs include service provider allocations (e.g., information technology support) and construction overhead allocations. The loadings and allocations effectively move costs from certain sections of the income statement to the balance sheet and correspond with accepted FERC accounting. These indirect costs and the allocation percentages are not known at the start of a project, therefore what matters for project management and applications such as setting a cap, is the incurred or direct capital cost spent directly on the project.

Table 2
Capital Costs for Electric Avenue and TriMet Pilots

Direct/Incurred	**$3,018,255**
UM 1811 - Electric Avenue	$2,390,130
UM 1811 - TriMet	$ 628,125
Loadings and Allocations	**$357,248**
UM 1811 - Electric Avenue	$356,850
UM 1811 - TriMet	$398
AFUDC	**$17,299**
UM 1811 - Electric Avenue	$15,397
UM 1811 - TriMet	$1,902
Grand Total	**$3,392,804**

Q. What is your request of the Commission?

A. Because Commission Order No. 19-385 states that maximum allowable costs do <u>not</u> include indirect costs, we request that the Commission allow all, except for the $3,125 reduction we agree to above, of expenditures for the TriMet, and Electric Avenue pilots in rate base and deny Staff's recommendation to permanently disallow this investment.

H. Salem Electric Avenue

Q. Why does Staff recommend removing $151 thousand dollars permanently from rate base for Salem Electric Avenue?

A. Staff states that Salem Electric Avenue site is no longer used and useful or operational since the last rate case.[47]

Q. Please provide more context about Salem Electric Avenue and why it has been closed due to construction at the Oregon State Capitol Building for the past two years.

A. Salem Electric Avenue opened in September 2019[48] and is located at 900 Court St. NE, in Salem, next to the Oregon State Capitol Building. In July 2021, the site-host requested that PGE remove the electric chargers due to a multiyear construction project at the Oregon State Capitol, as the construction project impacted the sidewalks and roadway infrastructure surrounding Salem Electric Avenue. The make-ready at that site remains used and useful and chargers are on-track to be re-installed in August of 2024.

Q. What is your request with respect to the Salem Electric Avenue charging investments?

A. We respectfully request the Commission reject Staff's recommendation for disallowance as the Salem Electric Avenue chargers were a prudent investment, which served customers, and the temporary closure of the Salem Electric Avenue was a reasonable course of action outside PGE's control given the site host construction project.

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[47] Staff/2200 Shierman/8.

[48] The Level Two chargers there were installed in September 2019 and the Direct Current Fast Chargers (DCFC) were installed in January of 2020.

I. Electric Island

Q. Please summarize Staff's recommendation regarding PGE's Electric Island project.

A. Staff recommends permanent disallowance for the Electric Island investment on the basis that PGE was not authorized to fund the project by a Commission-approved tariff and, a claim that the project did not incentivize an increase in charging infrastructure.

Q. As Electric Island is a capital investment contribution and PGE typically doesn't have Commission authority prior to investments, please explain more about Staff's objection to these expenditures.

A. Staff objects that PGE had executed a contract with Daimler Trucks North America (Daimler) to build a public charging station to refuel heavy-duty electric vehicles prior to having a tariff in place to provide these services; Staff states that a tariff cannot apply retroactively to an investment already made. PGE concurs that the contract was signed before the tariff was approved, however it is not outside of standard practice to engage with customers prior to the development of a tariff to ensure that there is interest in the pilots or programs to be proposed. Staff's objection focuses on the prudence of the project to provide customers with incremental benefits.

Q. Do you agree with Staff's recommendation to disallow the Electric Island project?

A. No. We believe that PGE's investment in the Electric Island project was prudent and reasonable and should not be disallowed. There are numerous benefits to customers from PGE's partnership in this project which include:

1) economic savings, where PGE estimates that there are at least $1.7 million in benefits associated with Electric Island, which more than outweigh the capital expenditure,
2) customer and public access to heavy-duty vehicle charging and interoperability testing,

3) learnings regarding heavy-duty charging infrastructure combined with grid-beneficial technologies and learnings as pertains to interoperability testing, and
4) broader support of the state's TE goals to advance the societal goals of transportation electrification.

Q. How does Electric Island benefit customers through system benefits and access to charging?

A. PGE provided a detailed analysis of the system benefits of Electric Island in PGE's Response to UE 389 OPUC Data Request No. 33. This analysis showed Schedule 53 could provide PGE with approximately $4.0 million in benefits from the avoided construction of new feeders, the avoided reconductoring of feeders, improved availability of future vehicle to grid and demand response technologies, and the development of safety and training protocols. Because Schedule 53 was designed to accommodate from one to three heavy-duty electric vehicle charging demonstration sites, PGE estimates that at least one-third of these benefits could be attributed to Electric Island, resulting in approximately $1.4 million in associated future benefits.

We also anticipate that Electric Island will provide grid services from the planned deployment battery energy storage systems, demand response-enabled charging infrastructure, and vehicle to grid-capable charging infrastructure. PGE valued these benefits for the one to three sites at $0.9 million. PGE again proposes that one-third of these benefits be attributed to Electric Island, resulting in approximately $0.3 million in associated benefits. Combined, these $1.7 million in benefits more than outweigh the capital PGE seeks to recover for Electric Island.

Lastly, PGE's involvement in the project ensured customer and public access to this charging infrastructure, which would not have necessarily happened without PGE's early support and involvement.

Q. Did the Electric Island project provide learning opportunities to advance transportation electrification?

A. Yes. There were significant learnings during the design and construction of Electric Island, including site layout, and recommended civil/structural practices for installing the chargers so they can be replaced by newer equipment. These experiences were presented at the Oregon Solar + Storage conference, the Sustainable Fleet Technology Conference and Exposition, the Green Transportation Summit & Expo, the EPIC Forum: Innovative Technologies to Accelerate MHD Electrification, the UTC Telecom & Technology Conference, the Fuels Institute, the Department of Energy-Department of Transportation-Environmental Protection agency Infrastructure Coordination meeting, the Pacific Coast Collaborative (PCC) Zero Emission Vehicle (ZEV) Infrastructure Working Group and the National Association of State Energy Officials (NASEO) conference. The presentations have also stimulated follow-up conversations with Oregon customers around how they might integrate Medium Duty (MD) and Heavy Duty (HD) charging into their own infrastructure buildouts.

In addition, Electric Island serves as a location for interoperability testing; interoperability testing is critical to ensure that vehicles can communicate and start charging with a variety of hardware/software charging options. Customers such as TriMet and FlixBus use the site to quickly test whether their EVs can complete the "handshake" and successfully charge with different chargers. Electric Island currently has eight DC Fast Chargers representing seven different models, allowing a testing opportunity that is not widely available across the state, or even the nation.

Q. How does the Electric Island project further the state's TE goals?

A. The early learnings captured from Electric Island will enable PGE to serve heavy-duty vehicle charging loads in a more cost-efficient manner, benefiting all customers. Learning from this project also aligns with HB 2165, which recognizes a significant role for utility infrastructure investment in transportation electrification, including behind the customer meter.

Q. Please summarize how Electric Island expanded public knowledge about TE.

A. Since its energization in April 2021, the Electric Island site has hosted several events with public officials, including the clean energy bill signing ceremony headlined by Governor Brown and subsequent visits by U.S. Senator Merkley and U.S. Representative Bonamici, as well as the Joint Office of Transportation. These visits promote the investments that PGE, vehicle manufacturers, and EV charger manufacturers are committing to the MD and HD charging space in Oregon, and garnered significant press nationally.

PGE hosted well over two dozen site tours at Electric Island. Attendees have included developers, consulting firms, public officials, EV charging manufacturers, heavy-duty truck manufacturers, local and regional transportation-focused non-profits, truck stop operators, truck fleets, charge network providers, electric utilities, and students from local universities. Daimler has also hosted several fleet customers interested in electrifying their fleets at the site. The range of questions and the eagerness of the audience to learn more during these tours has been tremendous, and the broad sharing of lessons-learned will increase the successful spread of MD/HD vehicle charging.

Q. Do these benefits support a finding that those capital expenditures were prudent?

A. Yes. Had PGE not invested in this project, the benefits described above would not be possible. The benefits to the public and customers more than outweigh the capital spent on this project and there will be more benefits to come as the market continues to advance and evolve.

Q. What do you request of the Commission?

A. We request the Commission reject Staff's recommendation to disallow the recovery of capital related to Electric Island. The Electric Island project is prudent due to the benefits that will accrue to customers of significant avoided system costs, increased public awareness of TE, making heavy-duty vehicle charging infrastructure available to the public and the crucial learning opportunities it has provided for PGE and many other interested parties.

J. TE Database

Q. Please summarize Staff's recommendation regarding PGE's TE Database.

A. Staff recommends a permanent reduction in rate base of $125 thousand for the TE database integration project based on the rationale that PGE failed to demonstrate economic benefit to customers.[49]

Q. Please describe the TE Database integration project.

A. This project created a TE database where none existed. Revisions to Division 87 rules created requirements to track specific PGE program-supported charging ports. This analysis cannot happen without a database to collect, standardize, and clean the data before analysis and reporting can occur. The limited data tracked before the database project was insufficient to perform the analyses required to meet Division 87 rules and guidance under order 22-314 (e.g. Div 87 performance metrics) or to evaluate program performance. When the

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[49] Staff/2200, Shierman/7, at 17 to 18.

Transportation Electrification Investment Framework guidance on Division 87 and the metrics for Portfolio Performance Areas were developed, it was clear to PGE that a database would be needed to collect and maintain the data to meet the analysis requirements across TE programs.[50]

Q. In addition to compliance with Division 87, how does the TE database benefit customers?

A. Much of the data in the TE database comes from the customers enrolled in our programs. As part of the database project, PGE developed an online intake form that customers fill out, which feeds data into the database. Since the customer in-take form went live in February of 2023, 173 customer registration forms have been submitted. The TE database currently contains data for 690 EV chargers across 113 commercial customers and 10 different TE programs and is tracking over 13,000 charging sessions per month.

Q. Why is Staff's application of an economic benefit cost standard to the TE Database inappropriate as the only measure of customer benefit?

A. Economic benefit is one criterion but not always applicable particularly for a foundational capability where new work is emerging. Staff does not consider that this project contributes to regulatory compliance and customer ease of doing business in their determination of prudence. PGE made the reasonable business decision to standardize the online form across programs to feed into one centralized database. Without the intake form and database, PGE would have to contact each customer directly to get the information needed to run reports and eventually perform analysis. PGE had no ability to run a benefit-cost analysis as there was no

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[50] *In the Matter of Public Utility Commission of Oregon Investigation of Transportation Electrification Investment Framework*, UM 2165, Order No.22-314 (Aug 26, 2022). https://apps.puc.state.or.us/orders/2022ords/22-314.pdf

separate comparative database and it was too speculative for PGE to estimate labor saved given the unknown nature of the work and scope of future charging installations.

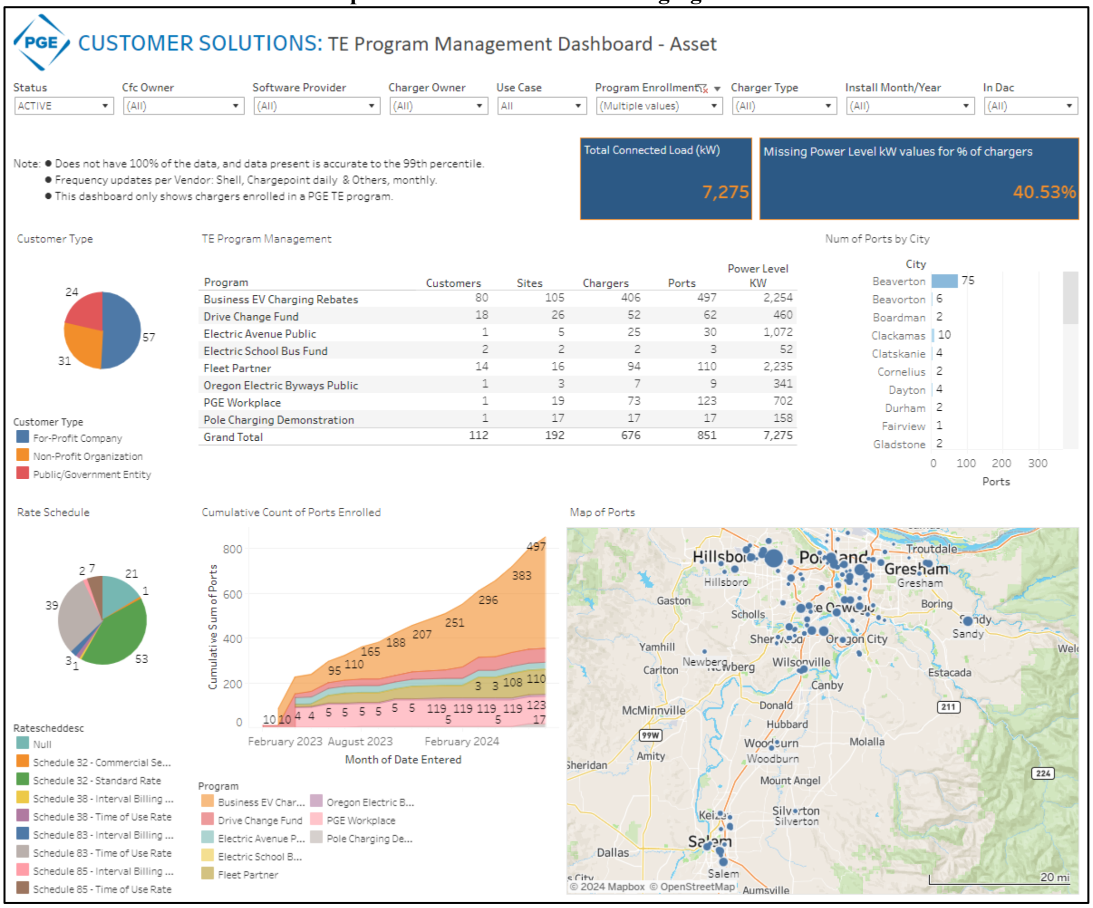
Q. How did PGE respond to Staff's request to justify the TE database project?

A. PGE Response to UE 416 OPUC Data Request 810 stated:

> In July of 2022, PGE evaluated the existing state – TE data held in disparate systems requiring significant manual effort for reporting purposes – and concluded that integrating and standardizing this data in PGE's data lake would be best practice. This is especially true given the anticipated expansion of activity in the TE portfolio. There are no formal work papers to document the evaluation for this approximately 130 thousand dollar project that will prevent significant future manual workload needs as TE programs expand.

We disagree that the standard for demonstrating prudence on this type of investment is only an economic benefit-cost analysis. The TE Database is a foundational investment for compliance with Division 87 reporting, which will maintain a growing volume of charging data that allows for customer intake form justifies this investment of $125 thousand.

Figure 1
Transportation Electrification Charging Database



Q. What do you request of the Commission?

A. PGE requests the Commission deny Staff's recommendation for permanent disallowance of the rate base associated with the TE Database of $125 thousand on the basis that the TE Database serves customers, provides needed technology to track voluminous charging session data, provides enhanced customer experience from data intake form and is used for compliance with Division 87 requirements.

VI. Qualifications

Q. John McFarland, please summarize your qualifications.

A. I received a Bachelor of Science in Business Administration from Miami University, a Master of Business Administration from Northwestern University, and a Master of Science in Quantitative Management and Analytics from Duke University. I served for eight years in finance and management roles at Procter & Gamble and served as Director, Global Digital Experience & Connected Vehicles at General Motors. Between 2022 and July 2024 I was Chief Operating Officer and then Chief Executive Office at FirstElement Fuel, a hydrogen fueling network. I first joined PGE in April 2019 until May 2022 and then came back to PGE in July 2024 as the Vice President Chief Commercial and Customer Officer where I oversee customer experience and development of new strategies to meet the changing needs of the customer.

Q. Elyssia Lawrence, please summarize your qualifications.

A. I received a Bachelor of International Studies from Crown College and an Executive Master of Business Administration from the University of Oregon. I have worked at PGE since 2002, with the majority of the time prior to becoming the Senior Manager of Product Management for Transportation Electrification in roles within our Customer Service area. My experience in the Customer Service area includes Billing and Meter Data Manager, Billing, Credit and Payments Manager, Network Data Operation Manager, Change Management for transformational system and process change project, Billing and Cash Remittance.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Transmission and Distribution

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Kellie Cloud
Franco Albi
Kevin Putnam

August 14, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Kellie Cloud. I am employed by PGE as the Senior Director of Wildfire and Operational Compliance.

My name is Franco Albi. I am employed by PGE as the Director of Regional Integration and Systems Evolution.

My name is Kevin Putnam. I am employed by PGE as the Senior Director of Engineering and Design.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues and proposed adjustments raised by the Staff (Staff) of the Oregon Public Utility Commission (OPUC or Commission) and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to PGE's transmission and distribution (T&D) operations and maintenance (O&M) expenses. We further clarify the basis for the proposed capital investment tracking mechanism, the Investment Recovery Mechanism (IRM). We will also respond to questions we received from The Oregon Citizens' Utility Board (CUB) regarding our work with customers during the January 2024 storm event.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have eight sections:

- Section II – Overview & Summary
- Section III – Utility Asset Management (UAM) O&M Expenses
- Section IV – Routine Vegetation Management (RVM) O&M Expenses
- Section V – Virtual Power Plant (VPP) O&M Expenses
- Section VI – Proposal Capital Project Adjustments
- Section VII – Investment Recovery Mechanism (IRM)
- Section VIII – January 2024 Storm Response
- Section IX – Qualifications

II. Overview and Summary

Q. What adjustments are being proposed by Parties specific to O&M?

A. Staff and AWEC are proposing adjustments to T&D O&M as follows:

1. Staff proposes reducing PGE's Utility Asset Management (UAM) program spending by $5.9 million. Staff's reduction is supported by comparing the 2025 Test Year to 2023 actuals and escalating using the All-Urban Consumer Price Index (CPI).
2. Staff and AWEC both propose reductions to PGE's Routine Vegetation Management (RVM) program. Staff proposes a $6.2 million reduction based on analysis claiming an unneeded increase in crew counts to perform this work. AWEC proposes a $4.3 million reduction which would hold PGE's RVM spending flat between 2024 and 2025.
3. Staff proposes that the Commission reject all of PGE's proposed $4.0 million increase to Virtual Power Plant (VPP) on the premise that PGE has not shown much progress and that some of the money proposed overlaps with PGE's grant program, representing a double-count. Staff further recommends that PGE host a workshop to provide details on the differences between VPP, Advanced Distribution Management System (ADMS) and Distribution Energy Resource Management System (DERMS). Finally, Staff recommends opening a new docket for PGE to file regular reports on the status of VPP.

Q. Please summarize PGE's position on these O&M related issues.

A. PGE responds to the issues above as follows:

1. We recommend that the Commission reject Staff's UAM proposal. PGE disagrees with Staff's use of both 2023 actuals and the All-Urban CPI as a basis for determining these amounts. Using 2023 as a baseline improperly attempts to relitigate the results in UE 416, especially since Staff's analysis does not consider PGE's actual ROE for 2023,

which was well-below authorized. Furthermore, we argue that the use of an All-Urban CPI is inferior when better, more specific information is available for escalating certain values. In PacifiCorp's, UE 374 General Rate Revision Docket, the Commission found the use of industry-specific information more appropriate than the use of a CPI index for forecasting test-year expenses.

2. We request that the Commission reject both Staff and AWEC's proposed reductions to RVM. Staff's position is based on inaccurate crew compliments and count, as detailed in Section IV. They also continue to improperly use All-Urban CPI despite the availability of better information. AWEC's proposal is not based on any specific analysis of the supporting information provided by PGE.
3. We recommend that the Commission approve PGE's $4.0 million increase to VPP. Staff's assumptions regarding a double-counting of costs related to PGE grant spending is inaccurate. Further, Staff is proposing a double-count with this item given that the majority of the dollars are for new Full Time Employees (FTEs) and Staff already proposed overarching reductions to FTEs. PGE agrees to host a workshop to better inform Staff of the intersections between VPP, ADMS, and DERMS. We recommend the Commission reject Staff's proposal to open another docket in order for PGE to provide reporting on VPP, as this is a topic that is already reported through the Multi-Year Plan and the Distribution System Plan.

Q. Please summarize the capital issues PGE is addressing in this testimony.

A. The Parties make the following capital-related proposals:

1. Staff proposes reducing the total plant of three specific projects by $8.6 million to reflect underspending on the projects, which have gone into service.

2. Staff proposes reducing total plant by $29.2 million for project contingencies since they do not know what the basis will be for incurring the amounts and cannot determine the prudence of the spending.

Q. Please summarize PGE's position on these capital related issues.

A. PGE responds to the capital related issues above as follows:

1. PGE recognizes that these specific projects are running below budget, however, Staff's proposal overlooks trailing costs for these projects, which have already increased the cost of the projects by approximately $1.5 million since Staff performed their analysis. PGE would agree to allow only actual spending on these three projects to go into customer prices based on information as of December 1, 2024.
2. We request that the Commission reject Staff's proposal regarding T&D contingencies as this is a value related to projects that Staff has been provided information to review, and to determine prudence. Contingency amounts are cited within various project justifications from this case that have been provided to Staff. Further, PGE can support all but 58% of the T&D contingency has been used for the past two years and would alternatively propose a reduction to the T&D contingency based on that percentage.

Q. Does your testimony address any other issues in this case?

A. Yes. PGE responds to other issues in this case as follows:

1. In Section VII, PGE clarifies the basis for its proposed capital investment tracking mechanism, the Investment Recovery Mechanism (IRM). The IRM was offered as a more efficient mechanism for cost recovery of needed investments without the considerable administrative burden that a GRC imposes on all Parties. However, based on the feedback received to date, we believe that the Company's

intent in proposing this mechanism has been misinterpreted and the role of the mechanism has been misconstrued. We are therefore withdrawing the IRM proposal at this time to ensure that adequate time and attention can be devoted to the other crucial issues in this case. Instead of requesting an IRM in this proceeding, we anticipate exploring a multi-year rate case approach in the future through conversations with other parties.

2. Section VIII of our testimony provides responses to questions CUB raises related to the storm event PGE's Service Territory experienced in January 2024. The additional information provided as part of this Testimony around our January 2024 storm response will highlight the extensive work our teams performed to communicate with customers and get them back in service as safely and quickly as possible under unprecedented and extenuating circumstances.

III. Utility Asset Management (UAM) O&M Expenses

Q. Please briefly summarize PGE's request concerning UAM O&M expenses.

A. PGE seeks recovery of $5.8 million in increased UAM O&M expenses for the 2025 Test Year, largely driven by increased contract labor costs and increased volume of inspections/corrections work across PGE's system.[1] This reflects increases in the Company's Facilities Inspection and Treatment to the National Electric Safety Code (FITNES) program, which involves inspecting and correcting the Company's aging infrastructure. These cost increases are necessary to maintain safety, reliability, and compliance.

Q. Please summarize Staff's opening testimony regarding PGE's UAM request.

A. Staff proposes to hold PGE's UAM O&M request to $25.9 million, consistent with the results of UE 416.[2] The basis of this adjustment is an escalation of 2023 actuals using a compounded CPI of 5.6%.

Q. What analysis does Staff provide to support this recommendation?

A. Staff outlines the nature of PGE's UAM work and the aspects of our FITNES program. They discuss the cyclical nature of our inspection and correction work and the increases in amount and cost of work for our FITNES program as detailed in PGE Exhibit 400. Staff, however, erroneously asserts that "no evidence was provided to support" these increased UAM program costs. As a result, Staff proposes an adjustment based on an escalation of the 2023 actual UAM costs.

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[1] See PGE/400, Bekkedahl – Felton/9-10.
[2] Staff/1300, Mondragon/21.

Q. Do you agree with Staff's use of 2023 instead of 2024 as the basis for their proposal?

A. No. We see this in part as an attempt to relitigate Docket UE 416 (UE 416). The final order in UE 416 established customer prices for 2024, and PGE appropriately uses that as the basis for comparison in this case. It is particularly appropriate given PGE's well-below-authorized ROE in 2023, which Staff does not consider in their analysis.

Q. Do you agree with Staff's assertion that insufficient evidence was provided to support PGE's 2025 forecast?

A. No. PGE Exhibit 400 outlines the nature of our UAM request and describes the work contained within the program. Our testimony details by program (inspection and corrections), by facility (underground and overhead), and by project type (Tape & Shape, O&M Work Orders, and Customer Side Corrections) the major cost drivers between our 2023 actual spend and our 2024 and 2025 forecast.[3]

Q. Please provide an overview of the information PGE provided to support your request.

A. For our FITNES inspections work, we outlined the specific drivers and cost increases, as well as our bargaining efforts to date. We detailed the status of our inspection ten-year strategic plans, and detailed how these programs are designed to protect PGE, communication workers, and PGE's customers by ensuring that construction, operations, and maintenance of overhead facilities meet Commission Safety Rules. Finally, we outlined how these plans impact our 2025 ask.

We discussed our three primary project types for our FITNES corrections work and the primary cost increase drivers for each. We specifically detailed service drops per pole by map grid and why we forecast increased Tape & Shape correction work in 2025. We discussed

[3] PGE/400, Bekkedahl – Felton/10-12.

historical and projected FITNES correction work orders and how these numbers fit with our ten-year strategic plan. Finally, we detail the historical labor and materials cost rates we are using to project future expenses for correction work.

Lastly, throughout our opening testimony on UAM, we describe how the safety and compliance nature of this work relates to the reliability of our system and is necessary on behalf of our customers to withstand increasing extreme weather events and other challenges to reliability.

Q. Was additional evidence provided in response to Staff data requests to support the increased 2025 UAM expenses?

A. Yes. In discovery, PGE provided additional evidence supporting increased 2025 UAM expenses, including additional inspection and correction program data, detailed numbers of inspections and corrections necessary to meet our ten-year strategic plans, further updates on labor contract negotiations and other price escalator information, and compliance and audit findings reports detailing the effectiveness of our UAM program. PGE has amply explained the reason for the Company's 2025 Test Year cost increases, primarily increased contract labor rates and increased work volume, as well as the crucial benefits these activities have for customers.

Q. What are the possible consequences and financial penalties if PGE is not able to complete our UAM inspection and correction work at the level requested?

A. PGE's FITNES inspections and corrections are designed to identify and remedy deficiencies of the National Electrical Safety Code (NESC) on PGE's system. Oregon recognizes the NESC through Oregon Revised Statute (ORS) 757.035 and Oregon Administrative Rule (OAR) 860-024-0010. Pursuant to NESC Rule 010B, NESC rules contain the basic provisions that are considered necessary for the safeguarding of the public and utility workers (employees and contractors). A utility is obligated to maintain its system in accordance with the NESC standards to protect both the public and its workers.

Not only are adequate inspections and corrections essential for safety reasons, but non-compliance with the NESC would expose PGE to the risk of civil penalties. For instance, ORS 757.990(1) provides for penalty of up to $10,000 for each such offense, per day. Moreover, failure to adequately inspect assets on a periodic basis and correct hazards in a timely fashion increases the likelihood of unplanned outages and increases ignition risk. Failing to comply with NESC standards is not an acceptable option for our customers, PGE, or the public.

Q. Do you have concerns with the method Staff is using to justify UAM adjustment?

A. Yes. In addition to our concerns raised about the justification and implications of the proposed reduction to necessary UAM work, we take issue with the application of the All-Urban CPI escalator to extrapolate the 2023 UAM actual spend levels to Staff's recommended 2025 Test Year amount. The application of an escalation factor for program O&M costs based on CPI is not an appropriate technique for setting Test Year rates. This method improperly attempts to relitigate the results in UE 416, especially since Staff's analysis does not consider PGE's actual ROE for 2023, which was well-below authorized. Furthermore, we argue that the use of an All-Urban CPI is inferior when better, more specific information is available for escalating certain values. In PacifiCorp's, UE 374 General Rate Revision Docket, the Commission found the use of industry-specific information more appropriate than the use of a CPI index for estimating test-year expenses.[4]

[4] See *In the Matter of Pacificorp, dba Pacific Power, Request for a General Rate Revision*, UE 374, Order No. 20-473, (Dec 18, 2020).

Q. What is your recommendation concerning PGE's filed UAM O&M expense forecast?

A. PGE asks the Commission to reject Staff's recommended $5.9 million adjustment and approve PGE's original cost recovery request. PGE has outlined the immediate and long-range scope of our inspection and correction work and the recent program cost pressures we have experienced. This information clearly demonstrates the prudence of PGE's increased UAM inspection and correction work and rates, as well as the necessity to complete this work to ensure compliance, safety, and reliability on our system.

IV. Routine Vegetation Management (RVM) O&M Expenses

Q. Please briefly summarize PGE's request concerning RVM O&M expenses.

A. PGE seeks recovery of $4.8 million in increased vegetation management expenses for the 2025 Test Year, largely driven by increased contract labor costs.[5] PGE provided substantial detail regarding the nature and scope of these expenses in direct testimony, workpapers, and through responses to discovery requests.

A. Staff Recommendations: RVM O&M Expenses

Q. Please summarize Staff's opening testimony regarding PGE's RVM program.

A. Staff outlines PGE's RVM cost recovery request and quantifies the differences between 2023 actuals, UE 416, 2024 budget, and the 2025 Test Year Forecast. Staff notes that all wildfire mitigation vegetation costs have been removed from base rates and will be recovered through the Schedule 151, Wildfire Mitigation Plan (WMP) Automatic Adjustment Clause (AAC) recovery mechanism.[6]

Staff notes establishing a balancing account to ensure that budgeted vegetation management work is being delivered, recognizing the importance of this work for safety and reliability. Staff also discusses establishing performance metrics related to this work and acknowledges Staff and PGE are still working on developing RVM metrics for the annual under-over collection amount.

Staff outlined their analysis of PGE's RVM proposal and developed several adjustments based on (1) number of crews and crew members, (2) crew hours, (3) crew rates, (4) outside contract levels, and (5) RVM non-contract escalation rates. Based on these items, Staff is

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[5] PGE/400, Bekkedahl – Felton/8.
[6] Staff/1300, Mondragon/8-9.

recommending a reduction of $6.2 million to the 2025 Test Year Forecast for RVM, which is at the baseline level agreed upon in UE 416.[7] We address each component of Staff's adjustment in turn.

Q. Please describe the proposed adjustment by Staff regarding the number of crews and crew sizes.

A. Staff proposes a downward adjustment to the PGE's costs for outside RVM crews based on a belief that PGE has increased the number of total RVM crews and crew members from the UE 416 filing. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Staff argues that the Company did not provide reasoning behind why they would require these additional crew members.

Q. Do you agree with Staff's adjustment as relates to their calculation of additional crews and crew members?

A. No. By choosing selective numbers from the UE 416 and UE 435 workpapers, and not reflecting the change in methodology between the two models, Staff is inaccurately calculating the crew compliment difference between the two dockets. **[BEGIN CONFIDENTIAL]** [redacted]

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[7] Staff/1300, Mondragon/17.
[8] *Id* 15.

[redacted] **[END CONFIDENTIAL]**

Q. Do you agree with Staff's application of UE 435 crew hours to the calculation of UE 416 crew compliments?

A. No. As mentioned previously, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. How did Staff analyze the outsource crew expenses in the 2025 Test Year?

A. Staff reviewed PGE's contracts with Asplundh Tree Expert Company (Asplundh) and reflected the average annual worker increase from 2024 to 2025 to their recalculated 2024 amount to arrive at their 2025 Test Year crew expense level.

Q. Do you agree with this method of using an average annual worker increase to calculate the outsource crew expenses?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. How did Staff calculate all other aspects of the RVM request?

A. In order to calculate the 2025 Test Year non-contract related RVM amounts, Staff used 2023 non-contract costs and then escalated this amount using the most recent All Urban CPI forecasts for 2024 and 2025.

Q. Do you agree with this method of reflecting non-contract related RVM amounts?

A. No. We take issue with the application of the All-Urban CPI escalator to extrapolate the 2023 non-contract RVM actual spend levels to Staff's recommended 2025 Test Year amount. As stated previously in this exhibit, the application of an escalation factor for program O&M costs based on CPI is not an appropriate technique for setting Test Year rates—particularly where there is available evidence concerning the Company's actual anticipated cost increases.

Q. Do you have any modifications to Staff's proposed adjustment to PGE's filed RVM ask?

A. Yes. Based on the information provided in our Reply Testimony, we are suggesting the Commission reject Staff's $6.2 million proposed 2025 Test Year adjustment and instead accept the Company's actual expense levels, based on the Company's detailed evidence concerning actual crew counts and contract rates.

Q. Does Staff address PGE's additional Forestry position request in this Docket?

A. No. Staff points to Staff Exhibit 1200 to discuss the additional Forestry positions PGE is requesting in this case. PGE Exhibit 1400 will address this adjustment.

Q. Do you have any comments regarding the recent actual and projected vegetation management efforts?

A. Yes. PGE's vegetation management efforts were established as part of a larger settlement in the UE 416 Rate Case. Vegetation management efforts are most effectively conducted utilizing a cyclical operational schedule. The operational plan provided as part of UE 416 includes a 3-year program with consistent funding and support.[9] Figure 1 shows, PGE forecasts improved program efficiency, allowing increased total number of line miles trimmed across the service territory utilizing the same number of forestry crews. Deviating from this plan puts dedicated resources at risk, jeopardizing PGE actions supporting compliance, system safety, and reliability.

Figure 1

Year	RVM Actual Spends/Budget Amount	RVM TARGET Line Miles	Actual Line Miles Completed/ Targets	Cost Per Line Mile Total Spend/ Target	Notes:
2020	$ 26,421,477	3,098	3,362	$ 7,859	Includes Bucket, Backlot, and Midcycle Linemiles
2021	$ 35,828,542	4,000	3,981	$ 9,000	Includes Bucket, Backlot, and Midcycle Linemiles
2022	$ 29,378,535	4,100	4,469	$ 6,574	Includes Bucket, Backlot, and Midcycle Linemiles
2023	$ 29,993,071	2,755	2,718	$ 11,035	Includes Bucket, Backlot, but NO Midcycle work
2024 YTD	$ 22,889,521	4,700	2,156	$ 10,617	Includes Bucket, Backlot, and Midcycle Linemiles
2024 Target	$ 53,695,549	4,700	4,700	$ 11,425	Includes Bucket, Backlot, and Midcycle work (MC -loaded in 1st half of year)
2025	$ 58,070,624	4,700	4,700	$ 12,355	Includes Bucket, Backlot, and Midcycle Linemiles

[9] *See In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 416, Order No. 23-386 at 12 (Oct 30, 2023).

While the cost of wildfire mitigation related vegetation management in PGE's High Fire Risk Zones (HFRZs) has been removed from base rates, RVM serves to reduce ignition risks outside HFRZs. Considering the increased frequency of extreme weather events and rapid climate change, failure to support PGE's vegetation management efforts would introduce a number of risks that would negatively impact customers, including wildfire and ignition risk, reliability impacts, and public safety concerns. Additionally, the risk of deferred line-clearance maintenance ultimately raises overall programmatic costs by introducing increased bio-mass along PGE's overhead conductor, driving up customer costs in future years while negatively impacting reliability and ignition risk in the short term.

Q. What has been the work to date on the establishment of performance metrics related to the vegetation management program?

A. PGE has been developing performance metrics related to vegetation management efforts. In the development of these metrics, PGE is focused on measuring customer value delivered through vegetation management, both routine vegetation management (RVM) and advanced wildfire risk reduction (AWRR). Measuring the customer value and effectiveness of RVM and AWRR includes the impact of vegetation management on ignitions and reliability as well as cost per line mile and cost per mitigation. This effort involves our internal Forestry staff, wildfire and asset risk experts, reliability engineers, geospatial analysts, OPUC Staff, external vegetation management experts, and information from national and international forums. A significant focus of this work has been centered around the recommendations of OPUC Staff as part of our UM 2208 – Wildfire Mitigation Plan (WMP) Docket.[10] Staff's final set of recommendations was detailed in a July 5, 2024 Report to the Commission. A large portion

[10] *See In the Matter of Portland General Electric Company Wildfire Protection Plan*, Docket UM 2208, PGE 2024 WMP Staff Recommendations Report (July 5, 2024).

of Staff's recommendations in the Report focused on the calculation of risk spend efficiency metrics and the application of these equations to demonstrate customer benefit. As a result of the Commission's decision approving PGE's WMP on July 9, 2024, PGE is in the process of refining our vegetation management metrics in preparation for ongoing discussions with stakeholders planned for fall 2024.

B. AWEC Recommendations: RVM O&M Expenses

Q. Please describe the proposed adjustment by AWEC regarding non-labor O&M expenses.

A. AWEC specifically identifies the increased spend on RVM efforts as a driver in increases to non-labor O&M distribution accounts. AWEC then compares 2023 actual costs, 2024 budgeted costs, and the 2025 Test Year request. AWEC acknowledges the increased amount in RVM spending approved for 2024 as part of the all-party settlement in the UE 416 Rate Case. AWEC then argues the 2025 RVM amount should be held flat to the 2024 approved increase given the need to evaluate the effectiveness of the heightened spending, and the rate pressures faced by customers. AWEC also argues that PGE should take efforts to find areas to prioritize spending and reduce costs elsewhere. This results in a recommendation to reduce PGE's overall non-labor distribution expense by $4.3 million.

Q. Do you agree with AWEC's adjustment that 2025 RVM rates should be held flat at 2024 levels.

A. No. AWEC was part of and signatory to the settlement agreement that set the 2024 level of RVM spending and recognized the need for that work. AWEC also acknowledges that PGE is executing on the elevated level of routine management work outlined in our 2024 budget. AWEC has not inquired about the effectiveness of our RVM spend and does not critique the methods or the crew contract rates used to estimate the 2025 increase. Their adjustment is solely based on holding rates flat at 2024 levels.

Q. What is the primary driver of the increase in 2025 RVM spend in the UE 435 Docket

A. As detailed in our Direct Testimony, the primary driver of the requested increase to the 2025 RVM request relates to the negotiated multi-year contract crew rates with Asplundh Tree Expert Company (Asplundh).

Q. Does AWEC question the use of the Asplundh contract rates in calculating the 2025 RVM test year amount?

A. No. AWEC does not take issue with the application of the 2025 Asplundh contract rates to the Company's RVM work.

Q. What are the implications of not reflecting multi-year contract escalation rates into expense categories as proposed by AWEC?

A. If the Commission were to agree with AWEC's argument that multi-year contract escalation costs should not be recovered in subsequent rate case proceedings, PGE would be disincentivized to enter multi-year contracts for services that benefit our customers.

Q. How do these multi-year contract rates benefit customers?

A. Typically, executing multi-year contract rates for outside services provides three areas of benefits for customers. First, committing to a multi-year contract generally allows PGE to negotiate lower rates than a year-by-year contract. Second, a multi-year contract agreement provides predictability and reduces price volatility for high demand labor such as tree trimming crews. Third, multi-year contracts ensure we have the services and labor necessary to complete our work. PGE's multi-year contract with Asplundh successfully secured resources that are in extremely high demand as utilities experience accelerating wildfire and other extreme weather risks and events.

Q. Do you have any modifications to AWEC's proposed adjustment to PGE's filed non-labor RVM O&M Expense?

A. Yes. Based on the information provided in our Reply Testimony, we are suggesting the Commission reject AWEC's $4.3 million proposed RVM 2025 Test Year adjustment.

V. Virtual Power Plant (VPP) O&M Expenses

Q. Please briefly summarize PGE's request concerning VPP O&M expenses.

A. PGE seeks recovery of $4.0 million associated with implementing the VPP program. These costs enable the Company to effectively orchestrate distributed energy resources (DERs) and flexible loads to provide substantial benefits for customers, including contributing to decarbonization, advancing customer and community resilience, facilitating customer engagement, and unlocking additional grid services.[11]

Q. Please summarize Staff's opening testimony regarding PGE's VPP request.

A. Staff summarizes the history of the Commission's support for PGE's past VPP expenditures, including Staff recommending approval of VPP costs as part of UE 416.[12] Staff acknowledges the critical role VPPs play in the future of Oregon's power system in a post-HB 2021 regulatory environment. Staff further comments that they are supportive of efforts to enhance PGE's DER capabilities through the VPP if the Company needs the funding and the efforts are providing customer benefits.

Despite overall support for PGE's VPP program, Staff recommends the Commission reject PGE's 2025 Test Year $4.0 million incremental VPP O&M expense request based on their review of support, development, training, and labor costs, and Staff's evaluation of progress-to-date on the VPP. Staff also recommends two additional actions to better communicate progress with the VPP. First, Staff suggests that PGE should hold a workshop with Staff and stakeholders to discuss how the Advanced Distribution Management System (ADMS), the DER Management System (DERMS), and the VPP all work together. Second,

[11] PGE/400, Bekkedahl-Felton/13-14.
[12] *See* UE 416, Order No. 23-386 (Oct 30, 2024).

Staff asks the Commission to open a standalone reporting docket for PGE to provide annual updates on VPP.

Q. What adjustment does Staff propose to VPP O&M expenses?

A. Staff proposes two adjustments: First, Staff proposes removing the entirety of the Company's start-up costs associated with the program, comprising a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction to 2025 Test Year expense.[13] Staff argues that these costs should be removed because they are "one-time" costs that should not be incorporated into base rates.[14] Second, Staff proposes a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Do you agree with Staff's adjustment concerning VPP start-up costs?

A. No. As described in our Direct Testimony, a significant portion of increased VPP program costs are driven by additional staffing needs to both implement *and operate* the VPP. These 2025 Test Year expenses include 13 full-time equivalents (FTEs), totaling approximately $1.6 million. These costs are ongoing and should be appropriately incorporated into base rates.

Moreover, Staff's adjustment double-counts its FTE reduction proposal. By recommending the disallowance of these additional positions in VPP O&M expenses, they

[13] Staff/1700, Dlouhy/11.
[14] *Id.*
[15] *Id.*

are double counting with the proposed FTE reductions provided in Staff Exhibit 1200.[16] PGE Exhibit 1400 addresses Staff's FTE testimony.[17]

Q. Do you agree with Staff's adjustment concerning PGE's [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

A. No. Staff's adjustment misunderstands the grant requirements. The VPP amount included in our 2025 Test Year request affiliated with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is a portion of our cost share of the program; there is no double recovery.

Q. What could be the impact of disallowance of VPP expenses necessary for cost sharing?

A. VPP expense recovery is necessary to be sure that PGE can fulfil its cost-sharing commitment **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. What analysis does Staff provide regarding their adjustment based on PGE's VPP progress since the last Rate Case?

A. Staff claims that PGE "has made essentially no progress" since PGE filed the UE 416 Rate Case and has failed to increase dispatchable resources or summer/winter flexible capacity.[18]

Q. Do you agree with Staff's assessment on the level of progress on our VPP?

A. No. The VPP customer programs enrollment and incremental MW growth has kept pace with prior years. Staff's calculation of comparing one year's capacity to another year's capacity does not accurately reflect the true nature of the growth in VPP participation. Each year, the historical capacity value for each VPP customer program receives adjustments based on past

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[16] *Id* 17.
[17] PGE/1400, Section III.
[18] Staff/1700, Dlouhy/11-12.

performance. This historical adjustment amount is calculated and reflected in the end of year actual to allow for a true year-on-year incremental growth calculation and ensure that it is reflective of actual prior year performance. This refactoring is inherent in customer program management and vital to understanding the MW capacity available from these customer programs.

Regarding VPP customer program capacity levels, PGE provided the MW capacity of each customer pilot-program through the discovery process (see Figure 2). The 2023 starting line provided is the 2022 actuals with the applied adjustments. Comparing the 2023 summer starting line of 86.96 MW to the end of year 2023 actuals of 96.84 MW reveals the 2023 incremental summer growth of 9.9 MW. Similarly, for 2023 winter, customer programs added an incremental growth of 3.2 MW. The 2023 incremental net growth was on par with prior years increasing by approximately 16,800 enrollments. The full MW capacity value adjusted annually combined with the incremental enrollment growth reflects the continuous progress increasing utilization of customer programs as VPP resources.

Figure 2

Table 1A. Summer Flexible Capacity Acquired (MW)

Flexible Load Customer Pilot Programs Portfolio	2022 Actuals	2023 Starting Line (1/1/23)	2023 Actuals	2024 Starting Line (1/1/24)	2024 YTD (as of 5/31/24)
Residential Smart Thermostat	33.76	33.76	39.95	38.99	40.85
Peak Time Rebates (PTR)	17.63	14.65	14.61	15.1	15.17
Time of Day (TOD)**	N/A	N/A	1.64	1.64	1.88
Energy Partner on Demand (Sch 26)	34.60	34.60	36.03	36.03	38.55
Energy Partner Smart Thermostats (Sch 25)	1.27	0.95	0.61	0.96	1.03
Multifamily Water Heater (MFWH)	4.45	2.00	1.96	1.96	1.88
Residential EV Smart Charging	1.00	1.00	2.04	1.04	1.21
Flexible Load Portfolio Total	**92.71**	**86.96**	**96.84**	**95.72**	**100.57**

Table 1B. Winter Flexible Capacity Acquired (MW)

Flexible Load Customer Pilot Programs Portfolio	2022 Actuals	2023 Starting Line (1/1/23)	2023 Actuals	2024 Starting Line (1/1/24)	2024 YTD (as of 5/31/24)
Residential Smart Thermostat	11.44	7.28	8.71	8.04	8.57
Peak Time Rebates	14.65	12.29	12.26	11.26	11.31
Energy Partner on Demand (Sch 26)	27.80	27.80	29.27	29.27	30.07
Energy Partner Smart Thermostats (Sch 25)	1.20	0.85	0.23	0.38	0.40
Multifamily Water Heater	6.68	2.56	2.51	2.4	2.3
Residential EV Smart Charging	1.00	1.00	2.04	1.09	1.26
Flexible Load Portfolio Total	**62.77**	**51.78**	**55.02**	**52.44**	**53.91**

**Starting line is the Year End MW, with a January 1 Planning Value Adjustment*
*** TOD included as Summer only at this time; MW not reflected in Winter totals*

Q. Can you provide recent examples of the effectiveness of PGE's VPP in terms of capacity savings?

A. Yes. During the most recent extreme weather event, PGE's VPP customers reduced electricity demand by nearly 109 megawatts (MW) during peak demand hours on Monday, July 8, and 100 MW on Tuesday, July 9, that is enough electricity to power over 90,000 homes for a four-hour period. PGE activated its entire portfolio of energy shifting programs, which approximately 200,000 customers participate in, to help alleviate strain on the grid due to record-breaking hot weather.

Q. How do you respond to Staff's comment that the Company's communication about the VPP has been ineffective to date?

A. We disagree. PGE's work on the VPP has been extensively documented and discussed, starting with the 2009 Pacific Northwest Smart Grid Demonstration Project exploring transactive control and DER optimization. The 2018 Flex Load Plan outlined PGE's vision for dynamic, flexible resources within the distribution system. Subsequent Multi-Year Flexible Load Plans detailed program activities, budgets, and cost-effectiveness scoring. The 2019 Smart Grid Report highlighted grid modernization efforts for DER integration. The 2021 and 2024 Multi-Year Plans advanced demand response modeling and value assessment. Throughout, PGE engaged stakeholders through various forums on VPP advancements, flex load initiatives, DER integration, and grid modernization.

Q. Staff believes there is some uncommunicated overlap between the VPP, Advanced Distribution Management System (ADMS), and DER Management System (DERMS) that warrants discussion and recommends that PGE hold an informational workshop to describe how they work together. Are you agreeable to conducting this workshop?

A. Yes. PGE supports Staff's recommendation to hold an informational workshop with Staff and stakeholders and suggests utilizing an existing DSP stakeholder meeting as the forum. As part of the workshop, PGE will demonstrate the stakeholder benefit of these systems and the distinction between and integration of the VPP, ADMS, and DERMS Company technology initiatives.

Q. Why does Staff believe that a periodic update on the VPP would be beneficial?

A. Staff asserts that given the infrequency with which the Flexible Load Multi-Year Plan is filed and the variety of other issues that are discussed, a targeted filing focusing on the current state of the VPP would provide clarity for planning and ratemaking purposes. Staff believes that this should be filed annually as a standalone, informational docket.

Q. Do you agree with Staff's assessment of the need for a standalone, annual reporting docket?

A. No. This proposal would be redundant to other efforts. PGE has communicated on the VPP through the Multi-Year Plan filing and the DSP process. In both, PGE outlines a comprehensive strategy for DER development, grid modernization, and VPP implementation, highlighting benefits for customers and communities alike. In these documents, we aim to detail our goal to optimize investments across stakeholders, ensuring that the transition to a bi-directional distribution system maximizes distributed resource and load management potential, lowers service costs, and enhances overall value.

If the Commission believes the Flexible Load Multi-Year Plan is not a sufficient vehicle for communicating the details of PGE's VPP, it could utilize the existing DSP process to fill in any perceived gaps. The DSP provides the 'roadmap' of how DERs and Flexible Loads identified in the IRP could be acquired, integrated, and orchestrated as PGE's VPP. The DSP also discusses the benefits of these activities to customers and the system. The DSP is the replacement to the former Smart Grid Report and is also a short-term and long-term action plan. As part of the DSP guidelines, and as part of PGE commitment to engagement, stakeholder meetings are regularly held to share and discuss content of the DSP as it is developed. Stakeholders provide valuable input from these that is informs revisions to the DSP prior to filing.

Q. What do you recommend regarding Staff's proposals on VPP?

A. We request that the Commission approve PGE's $4.0 million increase as this represents necessary funding to further the development of the VPP. PGE would agree to offering a workshop to the Parties to show how VPP, ADMS and DERMS benefit participants and intersect with one another. Finally, we request the Commission reject Staff's proposal to open yet another reporting docket when there are already multiple locations where information is already provided and reported to the Commission regarding VPP.

VI. Proposal Capital Project Adjustments

Q. Please briefly summarize PGE's request concerning T&D capital additions.

A. PGE seeks recovery of its incremental T&D investments made to serve customers through December 31, 2024,[19] including crucial resiliency and safety-related investments in grid modernization, substations, and enhanced distribution systems.

Q. Please describe Staff's proposed adjustment to PGE's T&D capital investments.

A. Staff proposes two types of adjustments to PGE's T&D capital investments. First, Staff proposes to remove costs associated with three discrete T&D capital projects based on preliminary in-service figures, which would result in a $8,610,215 revenue requirement decrease. Second, Staff proposes to remove PGE's contingency costs for all T&D capital investments, which would result in a $29,203,451 revenue requirement decrease. We address each category of adjustment in turn.

A. Three T&D Capital Projects

Q. Please detail Staff's proposed adjustment to three of PGE's T&D projects.

A. Staff proposes to reduce the Company's costs for (1) the Horizon-Keeler BPA #2 230kV Line (in-service Apr. 2024), (2) the Shute WJ1 and WJ2 Upgrade (in-service March 2024 and November 2023) , and (3) the Shute Feeder Reconfiguration (in-service March 2024) to these projects' in-service levels as of April 2024. Compared to the Company's as-filed revenue requirement request, Staff's calculation for the three projects totals $8,610,215.[20]

[19] PGE/400, Beddedahl-Felton/3.
[20] Staff/800, Ball/16

Q. How do you respond to Staff's proposed T&D capital adjustment?

A. Staff's adjustment does not account for outstanding invoices and costs that take time to process after a project enters service. Staff's proposed adjustment relied on the plant additions information through April 2024—which is the data that was available at the time. As PGE explained when presenting this data, some costs remained outstanding and final project costs were expected to increase.[21] By basing their proposed adjustment on preliminary plant addition totals, Staff does not fully reflect the true amount of plant going in-service.

Q. Do you have updated plant addition amounts for these three projects?

A. Yes, plant addition amounts for these three projects through July 2024 are provided in Table 1. The updated difference between the 2024 full year plant additions and the actual through July is $7,212,092.

Table 1
Plant Additions (January-July 2024)

Project	Actual Additions (Jan-Jul)	Forecast Additions (2024 Full Year)	Difference
Horizon-Keeler BPA #2 230kV Line	$34,406,884	$39,472,130	$(5,065,246)
Shute WJ1 and WJ2 Upgrade	$14,180,972	$14,898,016	$(717,044)
Shute Feeder Reconfiguration	$3,296,291	$4,726,093	$(1,429,802)
Total	$51,884,147	$59,096,239	$(7,212,092)

Q. What does PGE propose regarding these three projects?

A. PGE proposes to adjust the final plant in service for these three projects based on the projects' actual final values as of December 1, 2024.

[21] PGE Exhibit 1601.

B. T&D Contingencies

Q. Please describe Staff's proposed adjustment concerning contingencies for T&D capital investments.

A. Staff proposes to remove all project contingency amounts from T&D capital investments, which would reduce the Company's plant additions by $29,203,451. Staff calculated this adjustment based on project contingency amounts for all T&D capital investments in PGE's UE 435 rate base, minus project contingency amounts associated with the three projects already discussed above.[22] Staff claims that this adjustment is necessary because it is not yet known whether these costs will be incurred and, without knowing the specific reason contingency costs might be incurred, Staff cannot determine if the basis for incurring such costs is prudent and "were unavoidable with proper project management."[23]

Q. What are cost contingencies?

A. Cost contingencies are appropriate and industry-standard mechanisms designed to address a calculated degree of potential cost-related variability in major projects. No matter how diligently the Company works to control costs, some degree of cost uncertainty is inevitable in any major T&D effort. PGE therefore prudently seeks to account and plan for such uncertainties in developing final project budgets. Where a cost continency is used on major T&D projects, the amount is often approximately 10% of overall project costs, with some variation depending on specific project-related uncertainty. This cost contingency assessment is included in the Company's project planning process and is incorporated into a project's final projected budget.

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[22] Staff/800, Ball/17
[23] *Id*.

Q. Do you agree that it is appropriate to remove the entirety of PGE's contingency amounts for its remaining T&D capital investments?

A. No. Staff's claim that the prudence of projects with contingencies cannot be determined is inaccurate. The T&D contingencies included in this case have been allocated to projects, and Staff has received the project justifications for all of these projects to review the prudence and status of the work being done.

Q. Does PGE include some amount of project contingency for all T&D capital project investments?

A. No, as shown in Staff's T&D project contingency list, 55 of the 105 listed projects have no amount of project contingency calculated.[24] PGE applies project contingencies only where there is a need to account for uncertainty—the type of uncertainty not subject to avoidance through diligent project management.

Q. What would be the impact on PGE's capital project planning process if cost contingency is not part of the project management process?

A. Inclusion of some level of project contingency allows PGE to plan in an uncertain environment and accounts for some of the timing and cost risk inherent in large projects. Without some amount of contingency, PGE would wait until the best possible information is available before committing to a project schedule. This delay could ultimately result in higher costs for customers in an increasing cost environment.

Q. What do you request of the Commission?

A. We request that the Commission reject Staff's proposal to cut all T&D contingencies. Not only does Staff have the means to review the various projects that include contingencies,

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[24]Staff/802, Ball/11-14.

but making a blanket reduction to all contingencies would fail to recognize a necessary tool and industry norm for capital planning and budgeting.

VII. Investment Recovery Mechanism (IRM)

Q. Please briefly summarize the Company's IRM proposal.

A. PGE proposed an IRM tracking mechanism to enable efficient recovery for a subset of safety, reliability, and resilience-related investments outside of a traditional, labor-intensive general rate case model.[25] Without any additional tools, the need for substantial incremental investment means PGE must file a general rate case every year in order to have a reasonable opportunity to recover prudently incurred costs.

Importantly, PGE's proposal was time-limited, with an expiration date of December 31, 2030. Given that PGE's rate cases are driven by a period of substantial investment, PGE believed that this mechanism would provide an efficient mechanism for prudence review, while avoiding unnecessary administrative burdens on all Parties. This focused approach for PGE's anticipated high-investment period would also create long-term cost containment pressures on O&M.

Q. Please summarize the Parties' positions regarding the IRM.

A. Staff, CUB, and AWEC oppose adoption of the IRM. CUB characterizes the IRM as "one of the most far-reaching changes of ratemaking and incentives that [Mr. Jenks] ha[s] ever seen."[26] Meanwhile, AWEC states that PGE's proposal is not new, but should be rejected because it fails to meet the Commission's established guidelines for safety trackers.[27] Finally, while Staff opposes the mechanism generally, they propose a series of modification as an alternative, including (a) a three year stay-out for general rate cases, (b) accumulated depreciation updates for the class of eligible assets, and (c) application of an earnings test.[28]

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[25] PGE/400, Bekkedahl-Felton/16-18.
[26] CUB/100, Jenks/61 at 7-8.
[27] AWEC/100, Mullins/68 at 15.
[28] Staff/900, Stevens/38-39.

Q. What is PGE's response concerning the IRM?

A. Based on the feedback received and the degree of misunderstanding surrounding PGE's IRM proposal, PGE is withdrawing its IRM request at this time. Due to the extent of the misinterpretations, PGE believes that the IRM is excessively distracting from the issues in this case, which fundamentally concern PGE's request for cost recovery of prudently incurred costs to serve customers. We therefore address the mischaracterizations raised by the Parties only briefly, before returning to the core concerns in this proceeding.

Q. Please briefly address the Parties' mischaracterizations concerning PGE's IRM proposal.

A. AWEC and CUB make several statements that warrant clarification and correction.

- First, CUB's asserts that "PGE doesn't like the ten-month regulatory lag associated with traditional ratemaking, so it wants to shorten it."[29] This is incorrect. PGE's proposal continued to apply a year's worth of regulatory lag, but merely shortened the review period to reflect the reduced scope of the proceeding.
- Second, CUB states that the mechanism proposed adding "billions of dollars to rate base – without updating current rate base depreciation."[30] This is incorrect. PGE specifically proposed that the mechanism would include new capital investments and accumulated depreciation.
- Third, CUB states that "PGE knows getting billions of dollars in investments through general rate cases in the next four years will be challenging, so it wants a mechanism to facilitate rolling this investment into rates every winter with limited regulatory lag, limited

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[29] CUB/100, Jenks/55 at 18-19.
[30] *Id* at 20-21.

prudence reviews, and no examination of earnings."[31] This characterization does not agree with our IRM proposal. The regulatory lag would not be shorter; as noted above, the duration of lag would remain one year. Prudence review would not be limited; it would remain the same, simply focused on the assets to be added to rates. The amount invested would also not reflect the cost recovery that would be sought in a rate case; the mechanism was proposed for a specified subset of the Company's investments, and therefore would be substantially less than the cost recovery that would be sought in a rate case. CUB's concerns appear to be directed at a mechanism that it imagines PGE presented—not the mechanism actually proposed.

- Finally, AWEC states that the IRM is inconsistent with a generic policy for safety trackers *established by the Commission*.[32] This statement is misleading. The guidelines were a part of a stipulation between the gas utilities and intervening parties to Docket UM 1722.[33] PGE was not a party to this stipulated approach, nor does the stipulation apply generally to all energy utilities.

Q. What does PGE see as next steps regarding the appropriate matching of rates to the benefits received by customers through investments?

A. As stated previously and as suggested in our opening testimony in PGE Exhibit 400, PGE will seek to pursue a multi-year rate case in the future as an alternative to the IRM.

[31] CUB/100, Jenks/56.
[32] AWEC/100, Mullins/68 at 15-17.
[33] AWEC references this as Docket UM 1772, PGE determined it is Docket UM 1722.

VIII. January 2024 Storm Response

Q. Please provide some background on the January 2024 storm event, raised in this proceeding by CUB.

A. From January 13 through January 20, 2024, three distinct waves of wind and winter weather impacted PGE's service territory resulting in widespread damage and power outages across the Willamette Valley. The Portland metro area was below freezing for an unprecedented 118 continuous hours. In addition to the cold temperatures, persistent east winds brought gusty conditions and freezing rain to the Portland metro area throughout the week, accumulating 0.1 to 0.78 inches of freezing rain.

The unique challenges presented in this storm, including sustained high winds, ice, snow, and downed trees were met with monumental efforts by PGE crews, management, and support personnel. This storm also provided the opportunity to identify the limitations in existing processes and technology. The following Q&A will provide more details to the challenges, successes, and lessons learned from this event.

Q. What concerns were raised about the January 2024 storm event by CUB in this proceeding?

A. CUB raises general concerns about PGE's response to the January 2024 storm, stating that "there were real problems with PGE's outage response that [were] not helpful to the experience of customers that went beyond what was reasonable to expect during a winter storm."[34] On a concrete level, CUB identifies two issues with PGE's response: 1) that "PGE had fewer crews at work restoring service than they did during the last big storm, even though

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[34] CUB/100, Jenks/29.

the Company's service territory has grown";[35] and 2) that PGE's outage information reporting system is inadequate.[36] CUB asks PGE to address the following points in Reply Testimony:

- "Why was there an overall reduction in crews providing restoration? This was primarily caused by large reductions in contract and mutual aid crews."[37]
- "Does PGE have access to enough crews to ensure a timely restoration of power?"[38]
- Why did it take months after the outage for PGE to have reliable information about the number of customers who were out?"[39]
- "What is PGE doing to improve its outage response"?[40]

Q. Do you have any over-arching responses to CUB's characterizations and concerns?

A. Yes. First, as CUB is aware, the January 2024 storm event was an unprecedented and historic challenge to PGE's system. The series of winter storms caused widespread damage across PGE's service area, and PGE crews worked tirelessly through challenging conditions, such as downed trees and icy roads to restore power to customers.

Second, CUB's concerns regarding the January 2024 storm stand in stark contrast to CUB's position throughout the rest of this proceeding. Throughout this case, CUB argues that PGE must aggressively cut costs and reduce spending—seemingly regardless of the factual realities of the costs of providing service. Yet, in the face of concrete realities of a disaster response, CUB seemingly asks PGE to *increase* its costs. Apparently, CUB wants the Company to *increase* investment in outage reporting systems, to *increase* the number of field crews available to respond to outages, and to *increase* the Information Technology and

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[35] CUB/100, Jenks/29 (citing CUB/108).
[36] *Id* 31.
[37] *Id* 32.
[38] *Id*.
[39] *Id* 33.
[40] *Id*.

Solutions staff available to manage high-volume activities during major events. PGE recognizes the crucial need to restore service safely and swiftly during outages and maintain effective customer communications and agrees with CUB that these are systems and services worthy of investment for our customers.

Q. Regarding the January 2024 storm event, why was there an overall reduction in crews providing restoration? Was this primarily caused by large reductions in contract and mutual aid crews?

A. The overall reduction in crews providing restoration from the February 2021 storm to the January 2024 storm was because of the differences of magnitude and impacted geographic areas of the two storms. The January 2024 storm's total customers impacted was hundreds of thousands less than that of February 2021. Also, the impacted geographic area was concentrated to fewer areas. While the impacted geographic area in February 2021 covered almost the entirety of PGE's service territory, including the periphery of the territory with difficult locations to access (reason for differences in Outage Events in Table 2). Table 2 provides key metrics for the 2021 versus 2024 storm events highlighting the difference in the magnitude and scope of the events and the accompanying crew comparisons.

Table 2
Interruption, Outage, and Crew 2021 Comparison to 2024 Storm Event

	2021	**2024**
Customers Interrupted	683,344	397,780
Outage Events	18,628	4,293
PGE Crews	26	29
Contract Crews	200	163
Mutual Assistance Crews	44	9

PGE assesses potential impacts of a storm utilizing data analysis from past storm events and meteorological forecasts to try and pre-determine the number of crews necessary to preposition for response. There is a priority activation process that states the order of which PGE will activate crews; specifically, PGE internal crews, contract crews currently working for PGE, contract crews from adjacent areas, and then mutual assistance crews. During the preparation for storm response, PGE will also activate necessary support and ancillary services that will allow crews to perform repair in the most efficient and timely manner. PGE will also request out-of-area crews through multiple sources to secure resources in advance that can be available to contribute to restoration efforts as quickly and safely as possible.

Q. Does PGE have access to enough crews to ensure a timely restoration of power?

A. Yes, PGE has access to enough crews. However, the timely response of getting crews in place is dependent on several storm related factors. This includes weather and road conditions impeding travel of out-of-area crews, which occurred during the January Storm at Interstate 5 where numerous crews were stranded for over 10 hours. This affected crews for both PGE and Pacific Corp. Also, if there are other events or impacts to other utility's service territory, this can impact PGE's ability to secure closer crews. PGE utilizes the "closest forces" concept to secure crews and to have crews arrive as quickly as possible.

Q. Why did it take months after the January 2024 storm event outages for PGE to have reliable information about the number of customers who were out?

A. While PGE had identified customer count estimates during the January 2024 events, final impacted customer count from the January 2024 storm took time to reconcile due to several compounding factors:

- The magnitude of the storm event resulted in a large volume of outage data being input into PGE's Outage Management System (OMS) from multiple data sources/systems. This resulted in thousands of outage records for several days over the course of the event that needed validation and potential correction. The review, validation, and correction process for outage data from major storms of this magnitude historically span several months.

- PGE's OMS itself experienced performance and data accuracy issues during the event. A software defect caused a communications deadlock, leading to poor cache updating and an interface that did not reflect the current status properly. PGE had to repeatedly restart the system until a hotfix from the vendor Oracle could be applied. This had a direct impact to inaccurate outage data that later required manual intervention to correct.
- OMS configuration was designed to accept outage data from meter alarms, even when the alarm times were unknown or inconsistent with the actual outage event times. This caused inflated and inaccurate customer outage counts that required extensive review and validation.
- Customer outage reporting channels, including the public website, phone application and interactive voice assistant (IVA) systems, allowed customers to submit outage reports, which were automatically registered as actual outages in the OMS. During the storm, the system received dozens of duplicate reports from the same customers which accounted for hundreds of duplicate events, further exacerbating the data inconsistencies.
- PGE discovered a technical issue in the data correction process in the OMS that did not assign customer meters to the correct device when switching occurred. This caused inaccurate customer counts associated with outages and created complex scenarios to rectify those customer count inaccuracies. PGE has since fixed this technical issue in the data correction process for scenarios in which switching occurred.

- The volume of staff that support normal or "blue sky" processes PGE has in place for customer outage input, validation and correction is not such that we had the ability to absorb that large of an increase and meet the volume of outage data coming in during the storm. As a result, inaccurate or conflicting updates/inputs were made to the data through different channels through the course of the storm.

PGE continues to actively work to address its outage management and communication protocols, including currently upgrading our Oracle OMS, evaluating the OMS configuration and logic for meter alarms, improving functional capabilities to improve the accuracy of meter alarms, improving the process for filtering duplicate customer reports sourced from multiple channels, and developing automated logic to handle website submissions more effectively.

PGE has also made significant improvement over the last six months to expand the number of people trained to perform this outage validation and review work. Late in 2023, PGE began training 12 additional employees to perform outage validation and or correction in an effort to provide the most accurate customer outage data possible. Given the magnitude of the January event and the volume of outages that required post-validation and correction, we are assessing potential future resource needs to accommodate large events and are strategizing ways to make technological improvements to the systems and develop more automated reports to reduce the time it takes to provide reliable outage data as requested.

Q. What is PGE doing to improve its outage response?

A. PGE executive leadership has established an Outage Improvement Group (OIG) in 2023 that began reviewing and updating outage response procedures to provide greater outage response efficiency. A dedicated team of subject matter experts from different disciplines within the company have revamped PGE's damage assessment procedures. This will allow for intelligence gathering to be completed more efficiently and provide crews with a better understanding of repairs that will be required using PGE's mobile mapping and data acquisition application. Other operational processes that have been updated and exercised are onboarding of incoming resources, wire down identification and make safe operations, use of Circuit Captain concept to establish clear ownership of specific circuit restoration, Incident Management Team activation and role specific training, Emergency Support Roles for all PGE employees, and resource tracking using PGE's work management system.

Additionally, PGE recently completed a comprehensive outage management process analysis with the assistance of an external consulting group. The analysis included evaluating processes, systems, and reports in the IT, operations, customer, and GIS organizations within PGE. Recommendations from this analysis will be applied in phases, both short-term and long-term, to improve PGE's ability to more accurately capture and communicate customer outage information in a timely manner.

IX. Qualifications

Q. Ms. Cloud, please describe your qualifications.

A. I graduated Magna cum Laude with a Bachelor of Science in Engineering Science from Trinity University in 1995. I worked briefly as an instrumentation engineer in the oil & gas industry before returning to Oregon to work as a substation design consultant. I started at PGE in 2003 as a system protection engineer and progressed to manager of various engineering and field operations teams with an emphasis on quality assurance, compliance, customer service, and security. As director of substation operations, I focused on engineering, technician, and journeyman talent to enable transformation of the electric utility industry. As senior director of engineering services, I lead cross-functional teams to improve asset management across generation, transmission, distribution, and substation functions.

Q. Mr. Albi, please describe your qualifications.

A. I received Bachelor and Master of Science Degrees in Civil Engineering from Portland State University, and a Master of Business Administration from Marylhurst University. I have more than 20 years of experience in the utility industry. I have also completed various executive leadership development programs, including the Utility Executive Course and Energy Executive Summit through partnership programs at the University of Idaho. My employment with PGE started in January 2007 and I have held leadership responsibility for new generation construction, integrated resource planning, safety and training, virtual power plant integration, and strategy. Prior to PGE, I worked in engineering at PacifiCorp and the Bonneville Power Administration (BPA). I serve on the Electrification & Sustainable Energy Strategy Sector Council with the Electric Power Research Institute (EPRI).

Q. Mr. Putnam, please describe your qualifications.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Idaho. My employment with PGE started in January 2019 as Manager, Planning, Scheduling and Line Dispatch. I then held the role of Director, Utility Operations for the Programs, Design and Crew Coordination group. Prior to joining PGE, I served as Director, Field Engineering at PacifiCorp. I have held other engineering, leadership, and field operations management positions at PacifiCorp.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1601	T&D Plant Additions over $3M - Jan - April 2024

Exhibit 1601

T&D Plant Additions over $3M - Jan - April 2024

Project	Plant Additions Jan-Apr 2024	Originally Forecasted In-Service Date	Actual In-Service Date	Originally forecasted total project cost included as a plant addition for UE435 (2024 Full Year)	The contingency amount included in originally forecasted total project cost. (2024 Full Year, CE 2804)	Project Status Report
P37302-Horizon-Keeler BPA #2 230kV Line	$ 34,282,723	5/31/2024	4/25/2024	$ 39,472,129.77	$ 172,003	Project in service, final costs expected to be close to forecast amount
P37218-OH FITNES Distribution	$ 26,807,340	N/A - Ongoing Pole Replacements Project	N/A - Ongoing Pole Replacements Project	$ 128,561,086.59	$ -	Ongoing project, project work/costs below YTD estimates due to winter storms but projected to be at forecast by end of year
P37511-Construct Clearwater Wind Farm	$ 17,076,959	12/31/2023	1/5/2024	$16.9M is just the component attributable to the substation	$ -	The 2024 YTD costs/work is attributable to the substation portion of this project. Project was put in service on time and near budget.
P37214-Dist. Customer Line Construct III	$ 13,606,967	N/A - Ongoing Dist. System Construction	N/A - Ongoing Dist. System Construction	$ 19,388,446	$ -	Ongoing project, project work/costs higher than forecast YTD. This project is the same as P35925 project listed below. Dollars are split between the two Projects.
P37048-Outage or Emergency Replacement	$ 13,310,529	N/A - Outage/Storm Replacements	N/A - Outage/Storm Replacements	$ 15,079,836	$ -	Ongoing project, TYD actual plant additions higher than forecast due to winter storm damages.
P37366-Shute WJ1 and WJ2 Upgrade	$ 12,925,556	6/30/2024	3/28/2024 - WJ1 11/17/2023 - WJ2	$ 14,898,016	$ 250,000	Project in service, final costs expected to be close to forecast amount
P35890-Purchase Distribution Transformers	$ 9,466,764	N/A - Ongoing Dist. Transformer Purchases	N/A - Ongoing Dist. Transformer Purchases	$ 20,141,425	$ -	Ongoing projects, costs and work orders consistent with Year End Forecast.
P14628-Replace Failed Underground Cables	$ 7,887,867	N/A - Ongoing UG Cable Replacements	N/A - Ongoing UG Cable Replacements	$ 25,262,098	$ -	Ongoing projects, forecast work and costs are loaded in second half of year. Work orders and costs are expected to be at forecast by end of year.
P37213-Distribution System Construct III	$ 5,678,986	N/A - Ongoing Dist. System Construction	N/A - Ongoing Dist. System Construction	$ 11,282,623	$ -	Ongoing projects, costs and work orders consistent with Year End Forecast.
P36522-Distribution Automation	$ 5,034,821	N/A - Ongoing Dist. System Construction	N/A - Ongoing Dist. System Construction	$ 6,755,385	$ 480,000	Ongoing projects, costs and work orders consistent with Year End Forecast.
P37046-T&D Asset Relocation	$ 4,192,206	N/A - Ongoing T&D Asset Relocation	N/A - Ongoing T&D Asset Relocation	$ 9,428,628	$ -	Ongoing projects, costs and work orders consistent with Year End Forecast.
P35892-Purchase Customer Meters	$ 4,068,795	N/A - Ongoing Dist. Customer Meter Purchases	N/A - Ongoing Dist. Customer Meter Purchases	$ 11,538,208	$ -	Ongoing projects, forecast work and costs are loaded in second half of year. Work orders and costs are expected to be at forecast by end of year.
P36770-Street & Area Light Construction	$ 3,925,145	N/A - Ongoing T&D Asset Relocation	N/A - Ongoing T&D Asset Relocation	$ 11,917,095	$ -	Ongoing projects, forecast work and costs are loaded in second half of year. Work orders and costs are expected to be at forecast by end of year.
P37211-Substation Cap Rplcmts 2022-2024	$ 3,438,578	N/A - Ongoing Substation Asset Replacements	N/A - Ongoing Substation Asset Replacements	$ 6,205,474	$ -	Ongoing projects, costs and work orders consistent with Year End Forecast.
P37819-Shute Feeder Reconfiguration	$ 3,277,745	6/30/2024	3/28/2024	$ 4,726,093	$ -	Project in service, final costs expected to be close to forecast amount
P35924-Distribution System Construction II	$ 3,186,818	N/A - Ongoing Dist. System Construction	N/A - Ongoing Dist. System Construction	$ 7,047,612	$ -	Ongoing projects, costs and work orders consistent with Year End Forecast.
P35925-Dist. Customer Line Construction II	$ 3,018,575	N/A - Ongoing Dist. System Construction	N/A - Ongoing Dist. System Construction	$ 19,463,178	$ -	Ongoing project, project work/costs lower than forecast YTD. This project is the same as P37214 project listed above. Dollars are split between the two Projects.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Production

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Debbie Powell
Brian Clark

August 14, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Debbie Powell. I am employed by Portland General Electric Company (PGE) as the Vice President of Utility Operations.

My name is Brian Clark. I am the Senior Director of Thermal Generation and Planning.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues and proposed adjustments raised by Staff (Staff) of the Public Utility Commission of Oregon (OPUC or Commission) and the Alliance of Western Energy Consumers (AWEC) (jointly, Parties) with respect to PGE's 2025 test year operations and maintenance (O&M) generation amounts and generation related capital projects.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have seven sections:

- Section II – Overview & Summary
- Section III – Non-Labor Generation Expenses
- Section IV – Constable and Seaside Battery Energy Storage Projects
- Section V – Diesel Particulate Filters Project
- Section VI – Fleet Replacement Capital
- Section VII – Associated Energy Storage
- Section VIII – Qualifications

II. Overview and Summary

Q. Please summarize the O&M items PGE is responding to in this testimony.

A. Staff and AWEC are proposing adjustments to generation O&M as follows:

1. Staff proposes reducing PGE's non-labor generation forecast by $2.0 million related to the Clearwater Wind Project (Clearwater) Custer County impact fee.[1] Staff's recommended reduction is based on the claim that the cost can be absorbed into the prior year's budget.[2]
2. AWEC proposes a decrease to PGE's non-labor generation forecast by $5.8 million by inappropriately escalating all non-Clearwater or MMA costs by 5% from 2023 to 2025,[3] which ignores the commission-approved outcome from Docket UE 416 (UE 416). UE 416 authorized and established fair and reasonable rates for 2024.

Q. Please summarize PGE's position on these O&M-related issues.

A. PGE responds as follows to the issues above:

1. While PGE disagrees with the overall premise of Staff's proposal to remove the Custer County impact fee, PGE determined that this fee is capital and agrees to reduce the requested O&M by $2.0 million.
2. We recommend that the Commission reject AWEC's proposal on non-labor generation O&M. We consider AWEC's use of 2023 as the year to compare against 2025 as an inappropriate attempt to relitigate the results of UE 416, which established 2024 rates. AWEC does this while ignoring that PGE's regulated earnings in 2023 were 7.18%

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[1]Staff/1000, Anderson/3 at 8.
[2] Staff/1000, Anderson/3 at 11.
[3] AWEC/100, Mullins/32 at 5.

relative to an authorized ROE of 9.5%. We will also address specific errors identified within AWEC's analysis.

Q. Please summarize the capital issues PGE is addressing in this testimony.

A. The Parties make the following capital-related proposals:

1. Staff proposes that the capital for the Constable Battery Energy Storage System Project (BESS) (Constable) be reduced by $14 million and also propose a reduction of $44 million for the Seaside BESS Project (Seaside), to the extent the Seaside tracker is adopted by the Commission. Both reductions are based on comparing only one element of the cost, the Engineering, Procurement, and Construction (EPC) contract cost, to the total cost PGE has included for total plant in this case.
2. Relating to PGE's proposed tracker for Constable, Staff agrees to allow it to the extent that PGE provide an attestation when the project is in-service, that the plant be online no later than January 31, 2025, and that the total cost be the lesser of the EPC cost of $143 million or the actual cost.[4] AWEC requests that the tracker be rejected, and that Constable be included in PGE's revenue requirement to the extent it is in service prior to January 1, 2025.
3. Both Staff and AWEC oppose PGE's proposed tracker for Seaside. CUB proposes turning this tracker into one that moves the full revenue requirement to the in-service date of Seaside. CUB's proposal is discussed in Exhibit 1100.
4. Staff seeks to reduce by $17.8 million the amount collected for PGE's work installing new diesel particulate filters (DPF) based on actual dollars spent for sites completed in

[4] Staff/1700, Dlouhy/21-22.

the first part of the year combined with PGE's initial capital forecast for the sites to be completed in the latter half of the year.

5. Staff recommends reducing PGE's fleet replacement capital by nearly the entire amount of anticipated spend in 2024 based on their own analysis of PGE's fleet.

Q. Please summarize PGE's position on these capital-related issues.

A. PGE responds to the capital-related issues above as follows:

1. PGE recommends that the Commission reject Staff's proposals to reduce the plant values of the Constable and Seaside projects as Staff has conducted erroneous analysis by comparing EPC contract costs to full project costs, which is inconsistent with the previous capital cost recovery of Request for Proposals (RFP)-sourced assets.
2. PGE would agree to filing an attestation for the Constable project. However, while there are currently no indications the project will be delayed, PGE would alternatively recommend that the project online date be set as no later than February 28, 2025, to account for any unforeseen issues such as delays due to winter weather or equipment testing prior to confirmation of service readiness. Finally, PGE does not agree with using the EPC value for total utility plant as it is an unloaded value.
3. PGE requests that the Commission approve PGE's Seaside tracker to appropriately align the timing of the benefits customers receive with the prices they are paying when the costs associated with the project are incurred. PGE also offers to provide information on all capital prior to the effective date of Seaside to demonstrate no over collection as a result of the tracker. We also propose that the tracker be no more than the revenue requirement included in this case.

4. PGE requests that the Commission reject Staff's proposed reductions to the DPF project, as Staff's analysis uses stale data and because the importance of this project to customers directly corresponds to benefits received in Docket UE 436 (UE 436), PGE's power cost update tariff. Should amounts be removed from this case, there should be a corresponding reduction to power cost benefits within UE 436.
5. PGE requests that the Commission reject Staff's proposed reductions to PGE's fleet replacement costs, as the analysis Staff provided did not include the relevant data (i.e., the actual vehicles being replaced in this case), and PGE provides more context where Staff found our documentation to be inadequate to support recovery.

III. Non-Labor Generation O&M

Q. What are the Operations and Maintenance (O&M) Non-Labor Generation proposals made by Staff and AWEC?

A. Staff proposes removing $2.0 million in O&M for Clearwater that is forecast for Custer County impact fees.[5] Regarding the Major Maintenance Accrual (MMA) adjustments that PGE proposed, Staff found the cost escalation to be "reasonable and consistent with Staff's recommended method."[6] PGE provides an amended MMA workbook in accordance with PGE's response to Staff Data Request No. 472, submitted as a workpaper.[7]

AWEC proposes an adjustment following what they state are "traditional ratemaking standards," by comparing 2025 costs to 2023 actuals.[8] In their analysis, they hold Clearwater costs and MMA costs as PGE proposed and request that all other costs be escalated at 5% from 2023 to 2025, which results in an O&M decrease of $5.8 million.[9]

A. Staff's Proposed Reduction to Non-Labor Generation O&M Costs

Q. What is Staff's proposal regarding non-labor generation expenses?

A. Staff proposes reducing PGE's 2025 non-labor generation O&M forecast by $2.0 million related to Clearwater and the associated Custer County impact fee. Staff argues that the $2.0 million fee can be absorbed into the 2024 budget, and that doing so would keep this amount from carrying forward in rates beyond the obligation itself which ends in 2026.

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[5] Staff/1000, Anderson/3 at 8.
[6] Staff/1000, Anderson/4 at 8-9.
[7] *See* Confidential Workpaper "2025 GRC MMA Restated Workbook CONF"
[8] AWEC/100, Mullins/2 at 14.
[9] AWEC/100, Mullins/32 at 6.

Q. What is PGE's recommendation regarding Staff's adjustment?

A. While PGE disagrees with Staff's reasoning for their adjustment, upon further review of this forecast amount, PGE agrees to remove $2.0 million from O&M, as the Clearwater-related Custer County fee was determined to be capital and is included within the close-to-plant amounts for Clearwater. As such, we have removed this amount from O&M in our revenue requirement provided in PGE Exhibit 1301.

B. AWEC's Proposed Reduction to Non-Labor Generation O&M Costs

Q. What is AWEC's proposal regarding non-labor generation expenses?

A. AWEC suggests that PGE should have presented the O&M in its rate case by comparing 2023 to 2025. When looking at the non-labor O&M increases presented in the case, they claim that "the reasons for these increases are unclear,"[10] and state that PGE made analysis difficult by initially providing a version of PGE's response to AWEC Data Request No. 005 (DR 005) that contained some incorrect information.

Q. Did PGE provide 2023 O&M actuals for AWEC to perform an analysis of non-labor generation O&M?

A. Yes. As part of PGE's initial February filing in this case, PGE provided work paper support for all generation O&M costs, which included full accounting string level detail of 2021-2023 actuals, PGE's 2024 budget, and the 2025 Test Year. While PGE agrees that the initial response to AWEC DR 005 inadvertently contained incorrect information (which we later updated with a revised response), it is unclear why AWEC did not simply refer to PGE's initially filed work paper that contained complete and accurate values from the outset of the

[10] AWEC/100, Mullins/28 at 13-14.

case. Asserting that PGE's increase for generation is unsupported despite PGE providing this information at the beginning of the case is incorrect.

Q. Does AWEC's testimony challenge any specific increase to generation O&M non-labor?

A. No, AWEC makes no specific adjustments or decreases to generation O&M non-labor but rather recommends a general, unsupported adjustment that does not consider that PGE's 2024 budget is based upon the Commission approved outcome of UE 416.

Q. Does PGE agree with AWEC's use of 2023 instead of 2024 as the basis for escalation?

A. No. The Commission's Order No. 23-482 in UE 416 established customer prices for 2024. AWEC was a party to all applicable settlement agreements in UE 416. By asking PGE to use 2023 as the basis for rate making in this case, AWEC is relitigating 2024 and the results of UE 416. As stated in UE 416 PGE Exhibit 2000, PGE was facing an inflationary environment, and we were diligent in managing generation costs increases despite an increase in maintenance required for PGE's thermal and wind fleets. This diligence was shown in a comparison of total Generation Non-Labor O&M, which illustrated that PGE did not return to 2019 pre-pandemic levels of spending up until 2024.

Q. Why are actuals for 2023 not an appropriate comparison when evaluating 2025 forecast for this rate case?

A. In 2023, PGE's actual regulated utility results for Return on Equity amounted to 7.18%.[11] This is well below PGE's authorized ROE of 9.5% which shows that 2023 actuals are not indicative of what PGE realistically needs to maintain normal operations and have the ability to earn our authorized ROE. Earning our authorized ROE is necessary to attract investors, which is especially important for customers as they benefit from the reliability, safety, and

[11] See *In the Matter of Portland General Electric Company's Results of Operations Report*, Docket RE 119, PGE's 2023 Results of Operation Report (May 1, 2024).

environmental benefits made possible by capital investment.[12] Consequently, even though 2023 is the base year, it is not the right starting place in this instance, especially when newer information is available because 2024 has already been litigated.

Q. Are there any other issues that PGE found in AWEC's analysis?

A. Yes. Multiple errors were identified in Table 5 of AWEC Exhibit 100. For instance, Clearwater amounts are reported in this table as $5.0 million, when on the "Clearwater" tab of AWEC's non-labor O&M analysis workpaper these expenses total $5.5 million, as corroborated by the numbers provided in PGE's initial rate case filing workpaper referenced above. Further, Table 5 identifies $37.8 million worth of MMA expenses in 2025, but this number is far from accurate. As presented in PGE Exhibit 500 workpaper titled "FINAL MMA Workbook 2025 GRC_CONF," actual 2025 amounts to be considered in generation testimony are $21.1 million, and the 2025 MMA amount including Account 456 offsets is $16.2 million. For the purposes of analyzing generation increases, the $21.1 million number should be used. It should also be noted that PGE does not agree with the escalation rates used by AWEC,[13] and we would recommend using the escalation rates used by PGE in opening testimony.[14] As shown in PGE's response to OPUC Data Request No. 434, PGE has different escalators for different cost elements, making the escalation method more targeted and accurate than escalating every type of cost at the same rate. This more precise approach to

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[12] *See* PGE Exhibit 1800 for more information on PGE's ROE.
[13] AWEC/100, Mullins/32
[14] *See* PGE Exhibit 200, page 10.

determining escalations for non-labor O&M has been previously supported by the Commission over the All-Urban CPI.[15]

Q. What is PGE's recommendation regarding AWEC's adjustment?

A. PGE recommends the Commission deny AWEC's recommendation. AWEC inaccurately asserts that information was not provided, they inappropriately use of 2023 instead of 2024 for the basis of their adjustment and include errors in their analysis. A simple review of PGE's generation non-labor O&M increase from 2024 to 2025, excluding MMA expense and Clearwater, as AWEC themselves do in their analysis, exhibits a total increase of just 2.47% from 2024 to 2025.[16]

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[15] *See In the Matter of PacifiCorp Request for a General Rate Revision,* Docket UE 374, Order No. 20-473 at 111.

[16] *See* PGE Confidential Workpaper "Production Workpaper CONF", tab "Tables," cell N8 for information regarding this calculation.

IV. Battery Energy Storage Projects

A. Seaside and Constable Adjustments

Q. What proposed adjustments does Staff make to the Constable and Seaside projects?

A. Staff's proposal for both the Constable and Seaside battery projects begins with a discussion of the Request for Proposals (RFP) process, which references PGE's RFPs and implies that "this past history may dissuade bidders from participating in a future RFP."[17] This section culminates in a $5 million punitive reduction that intends to punish PGE for not providing over a decade worth of RFP data, most of which was already available to Staff in the 2018, and 2021 RFP dockets.

Staff also proposes a reduction of $14 million for Constable and a $44 million reduction for Seaside if PGE's tracker for Seaside is adopted. Staff's proposal points its justification to a communication between PGE and the Independent Evaluator for these battery projects, where Staff compares Engineering Procurement Construction (EPC) costs to total gross plant costs.

Q. Does PGE think that its involvement in past RFPs will reduce RFP participation in the future?

A. No. PGE finds the conclusion Staff makes to be at odds with historical precedent. With some effort (and after collecting information in dockets that Staff can fully access), PGE was able to put together Table 1, which shows resource procurement RFPs dating back to 2004.

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[17] Staff/1700, Dlouhy/19 at 2.

Table 1
RFP Participation

	2011 & 2012 Capacity and Energy Power Supply RFP	2012 Renewable RFP	2018 RFP	2021 RFP
Counterparties that submitted a bid:	12	26	8	18
Proposals submitted:	33	57	26	110
Benchmark proposals submitted:	3	5	3	15
Counterparties included in the final shortlist:	11	5	3	7
Proposals included in the final shortlist:	24	7	6	24
Benchmark proposals included in the final shortlist:	3	1	3	11

As this table demonstrates, PGE's RFPs have maintained robust participation, and the 2021 RFP had an incredibly high level of participation from start to finish. There was strong participation of all counterparties during initial bid submission and the final shortlist process. Also, in the final shortlist of the 2021 RFP, there was a strong inclusion of benchmark and non-benchmark proposals. The competitive RFP process is vitally important for ensuring that the least-cost and least-risk resources are selected for our customers, in addition to being overseen by an Independent Evaluator. The information above should address Staff's concerns about RFP competitiveness.

Q. Is it appropriate for Staff to address a discovery issue by demanding a $5 million punitive impact to a prudent investment for customers?

A. No. Such issues are more appropriately addressed through the procedural process and the Commission's regulations under the Oregon Administrative Rules for the handling of discovery disputes in contested cases. As such, we recommend the Commission reject Staff's proposal. Furthermore, the selection of a $5 million value is arbitrary. Staff provides little explanation, support, or analysis for the selection of this value.

Q. How does PGE respond to Staff's comments regarding the RFP process for Seaside?

A. We disagree with Staff's assertion that that PGE knew about the size change of Seaside well before the communications PGE presented to Staff during discovery in this case.[18] Staff also claims that a non-conforming bid could have been submitted, but this claim is also predicated on the false pretense that PGE left out responsive communications during the discovery period for this rate case. PGE finds Staff's account of events to be speculative and needlessly damaging.

To recount the timeline of the 2021 RFP, benchmark bids were due January 4, 2022. Best and final offers were due March 16, 2022. Final shortlist acknowledgment was submitted May 5, 2022. The Commission acknowledged the final shortlist on July 14, 2022, with a price refresh following on August 26, 2022. This all occurred in 2022.

It was not until 2023 that PGE first received official written communication about the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Staff interpreted the wording of this email communication to infer that PGE "was in contact with **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**."[19] The implication Staff makes may be due to the fact that the proposal was discussed verbally between **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** that was sent to PGE in order to provide a preview of the situation. PGE then asked that this change be submitted in writing, and that was the email communication that PGE provided in response to Staff Data Request

[18] Staff/1700, Dlouhy/27 at 12-13.
[19] Staff/1700, Dlouhy/27 at 1-2.

No. 174. Staff asserts in testimony that it would be "impractical for the Company and Eolian to submit a 200 MW option of their benchmark bid," and PGE agrees.[20]

Q. How does PGE respond to Staff's analysis of the Constable and Seaside project costs resulting in $58 million of reductions?

A. Staff's analysis fails to include key components of the project cost and should be disregarded. Staff compares only the EPC cost from PGE's contracts provided in discovery to the actual capital amounts included in this rate case which include EPC costs as well as owners' costs and capitalized costs during construction (interest, property taxes). These other costs are contemplated in the workbooks that PGE provided to OPUC Data Requests Nos. 171 and 173, as discussed below. Additionally, Staff references a stale gross plant value for Constable in this rate case as gross plant was updated three months ago to $158 million in the May 1 plant update. Staff's mismatching of values is the driver for their proposed adjustment.

Q. Please provide the appropriate details for each project.

A. For Constable, Staff identifies the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** million in the initial EPC contract for the project, but they fail to include allowance for funds used during construction (AFUDC) or owners' costs. PGE's response to OPUC Data Request No. 171, Attachment 171-A provided a 2021 RFP workbook that shows that Constable EPC/RFP costs are not total project costs.[21]

The amounts included in this rate case are $158 million,[22] which are made up of the final EPC cost of **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[20] Staff/1700, Dlouhy/28 at 3-4.
[21] *See* PGE Exhibit 1701HC
[22] PGE notes that approximately $3.4 million of this cost, which is functionalized as transmission plant, is included in PGE's base capital request.

[redacted] **[END HIGHLY CONFIDENTIAL]**[23]

For Seaside, when the final EPC contract cost of **[START HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** to the total plant balance included in this case of $396 million.[24] PGE's response to OPUC Data Request No. 173, Attachment 173-A provided a 2021 RFP workbook that shows that Seaside EPC/RFP costs are not total project costs.[25]

Q. What is PGE's recommendation regarding Staff's battery project adjustments?

A. We urge the Commission to consider the prudence of these projects with confirmation of PGE's fair and transparent RFP process, which selected the least-cost, least-risk assets that ultimately benefit our customers by keeping prices affordable as we continue to adopt clean, dispatchable resources during this clean energy transition.

As such, PGE recommends that the Commission reject Staff's proposed reductions. The reductions are based on incomplete analysis and/or are unsupported by facts—facts that are highlighted above, were established in PGE Exhibit 500 and through the discovery process.

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[23] The current contract/EPC cost for Constable is for **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** million of which is closing to plant in 2024. This change from the original contract cost originates from negotiations on prices and minor work scoping, and a change order was executed on July 10, 2023.

[24] May not total due to rounding.

[25] *See* PGE Exhibit 1702HC, please note that this workbook does not include the roughly **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** million worth of land cost.

B. Constable and Seaside Trackers

Q. Please briefly summarize PGE's proposed trackers for the Constable and Seaside projects.

A. PGE proposed to track and incorporate the revenue requirement impacts of the Constable and Seaside projects through updates to the cost-of-service rate schedules in the same manner as the rest of PGE's generation revenue requirement.[26] Using this approach avoids exacerbating PGE's considerable regulatory lag by facilitating timely recovery of prudent investments, while ensuring that customers promptly receive the benefits of these essential new projects.

Q. How does Staff respond to PGE's proposed tracking mechanism for Constable?

A. Staff finds PGE's Constable tracker acceptable, subject to several conditions: (1) that PGE provide an in-service attestation, (2) that Constable is placed in-service by January 31, 2025, and (3) that the gross plant included in customer prices constitute the lesser of $143 million or actual gross plant.[27]

Q. How does PGE respond to Staff's proposal regarding the Constable tracker?

A. PGE agrees to file an attestation when Constable is placed into service but would recommend that this requires the project be in-service no later the February 28, 2025. However, as supported by the information provided in Section A, PGE disagrees with Staff's comparison of the final utility plant value to the initial EPC contract-only cost.

Q. How does AWEC respond to PGE's proposed tracking mechanism for Constable?

A. AWEC rejects the use of a tracker for Constable and suggests that it be included in the rate case as a normal capital project, and subject to the same rigor and conditions. AWEC claims

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[26] PGE/900, Macfarlane-Pleasant/11.
[27] Staff/1700, Dlouhy/22.

that a tracker is "unnecessary" because PGE assumed the risk of not including Constable in rates when it filed this general rate case.

Q. How does PGE respond to AWEC's assertion that PGE does not need a tracker for Constable?

A. The Constable project, a large-scale utility battery facility, will provide significant benefits to customers through the clean capacity it enables. Assets of this magnitude, offering such substantial advantages to our customers, warrant consideration to ensure that rates accurately reflect the costs associated with delivering these crucial benefits. While PGE expects Constable to be completed prior to December 31, 2024, some general construction risk inevitably remains. While PGE does agree that Constable should be open to capital project analysis, a tracker is a fair and reasonable mechanism to allow for some timing fluctuations. All Parties have had an opportunity to fully evaluate Constable's prudence in this proceeding through the discovery process, and there is no basis for duplicating this review in a future rate case.

Q. How do Staff and AWEC respond to PGE's proposed tracking mechanism for Seaside?

A. Staff and AWEC oppose PGE's Seaside tracker on the premise that it shifts risk to customers, that PGE should have waited six months to file a rate case, and that "rate pressure concerns" warrant rejection of a cost recovery tracker.[28] AWEC further argues that the Seaside tracker "will produce a modest reduction to revenue requirement,"[29] and is analogous to a "disastrous"[30] tracker that the Commission previously approved for the Carty Generating Station (Carty).[31]

[28] Staff/1700, Dlouhy/29-32; AWEC/100, Mullins/59-61.
[29] AWEC/100, Mullins/59.
[30] AWEC/100, Mullins/60.
[31] AWEC/100, Mullins/60.

Q. What is your over-arching response to Staff and AWEC's arguments concerning the Seaside tracker and the adequacy of PGE's cost recovery?

A. PGE is a cost-of-service business where customer prices are meant to reflect the services customers are receiving. As discussed in Exhibit 1100 – Affordability Programs and Proposals, PGE's ongoing investments substantially outpace depreciation, even before any new large plant is added. The Seaside project is an important investment for achieving the climate change goals established by the Oregon legislature. Utility-scale batteries, such as Seaside, are needed to provide our customers with clean capacity during hours of peak energy usage. We see this as an important benefit as we move forward with a clean energy transition that has already posed risks to reliable service as other stable resources are retired.

Denying timely recovery of this battery will lead to significant under-recovery for PGE. To support its position, PGE would be willing to provide documentation on capital additions and depreciation on all assets prior to including Seaside in customer prices to show that PGE would be under-recovering on the whole and that customers would not be overpaying.

Q. How does PGE respond to AWEC's position that since PGE presents the tracker as a modest rate decrease a tracker is unnecessary?

A. First, this statement is in conflict with AWEC's position that rate pressure concerns should lead to a rejection of the tracker. Second, given that AWEC has proposed alternate treatment of the ITCs, they would be keenly aware that the modest rate decrease was driven by matching PGE's proposal for amortization of the value of the ITCs with the in-service date of the project.

Q. Do you agree that the Carty tracker was "disastrous"?

A. No. We do not agree. AWEC is conflating issues with the Carty project with the regulatory tracker itself. As context, in Docket UE 294, PGE requested a tracker for the Carty project, which was projected to be online by May 15, 2016. In an all-party stipulation adopted by the Commission in Order 15-356 on November 3, 2015, the Commission agreed to allow Carty to be tracked into customer prices after the plant entered service. The Commission limited cost recovery to the revenue requirement included in the opening filing of UE 294, required the plant be in-service by July 31, 2016, and directed PGE to provide an officer attestation of the project's in-service status.[32]

Subsequently, the Carty project experienced major challenges that led to significant cost overruns. None of those costs were included in the tracker. Thus, the structure of the tracker ensured that customers never paid for any of the cost overruns. Despite issues with the Carty facility's development (which were related to the project developer), the tracker appropriately enabled cost recovery while shielding customers from cost overruns.

Q. How is Seaside different from Carty?

A. Seaside is different from Carty in two important respects. First, Carty has frequently been mistaken as benchmark project – <u>it was not</u>. Second, the credit metrics of the bidding party that won the Carty build-own-transfer agreement were below the initial standards of that RFP. Conversely, the Seaside project is **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Thus, the risks that created problems with the Carty project are irrelevant to Seaside—let alone the Seaside tracker.

[32] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 294, Order No. 15-356 at 5-6 (Nov 3, 2015).

Q. What is PGE's recommendation regarding the Constable and Seaside trackers?

A. PGE recommends that the Commission approve PGE's proposed tracking mechanisms for Constable and Seaside, as these are reasonable and balanced mechanisms to enable timely recovery of prudently incurred costs. No party contests that these projects will greatly benefit PGE's customers. Adopting these tracking mechanisms will align project benefits with their associated cost recovery.

We would further propose that PGE offer additional detail regarding all capital up to the rate effective date of Seaside to show that customers will not be overpaying, and we would agree to only track the amounts included in the revenue requirement of the opening filing of this case into customer prices.

V. Diesel Particulate Filter Installation Project

Q. What is Staff's proposal regarding the Diesel Particulate Filters (DPF) Project?

A. Staff proposes to alter the capital included in the rate case for this project by taking actuals of currently completed sites and summing them with forecasts for sites that are yet to be completed. This method of project forecasting results in a decrease of $17.8 million.

Q. Does PGE have any issues with the analysis and methodology that Staff suggests using?

A. Yes. Staff uses a mismatched method of project forecasting that will leave this critical project without funding. Staff also uses an incorrect forecasted project amount in their analysis and does not acknowledge the need of this project and the benefit it provides.

Q. What is the DPF project?

A. This project installs Diesel Particulate Filters at various Distributed Standby Generation (DSG) sites, where necessitated by the Department of Environmental Quality's Mutual Agreement Order guidance. The conditions and requirements of these various sites can vary widely, but it is PGE's goal to ensure that we stay in compliance and avoid fines.

Q. What would be the potential consequences for customers if this project is not completed?

A. This is a critical project that could result in cost increases to our customers if not completed. As explained in PGE's Annual Power Cost Update, Docket UE 436 (UE 436), PGE Exhibit 100, contingency reserve obligation (CRO) changes through NERC have allowed PGE to serve more of this obligation through non-spinning reserves, which directly relates to the DSG program. This capital project will help bolster the DSG program and make it possible for PGE to meet these obligations. Additionally, this CRO change allows PGE customers to realize a $1.9 million benefit, a value Staff agrees is accurate in UE 436, Staff Exhibit 100. To achieve this benefit, PGE needs non-spinning resources, and we would have a reduced amount of non-spinning capacity if we do not complete this capital project.

Q. What project cost should Staff have used in its analysis?

A. Staff should have used PGE's May 1 capital project update for the most up to date and correct project cost. PGE's update has the DPF project at $42.9 million, while the original and now stale amount was $37.5 million. Also, the analysis that Staff conducted was based on the dates of site completion, and those are not finalized. For example, the site corresponding to Account Work Order (AWO) number 1000013919 has resumed for 2024, with an estimated completion date of December 15, 2024, and the site corresponding to AWO 1000013939 has resumed for 2024 with an estimated completion date of December 31, 2024.

Q. Is Staff correct to compare the project actuals provided in PGE's response to Staff Data Request No. 567 to the project forecast included in this case?

A. No. While PGE's response to Staff DR 567 included unloaded actuals by site, these numbers are also not final as noted in the data request attachment. More importantly, the use of these unloaded values is misguided because they are comparing to amounts inclusive of loadings and AFUDC within PGE's capital project documentation.

Another issue in Staff's analysis is their use of $300 thousand worth of actuals for AWO 1000013601. As mentioned in PGE's response to Staff Data Request No. 238, this AWO is a labor placeholder that applies to no specific project, and so both completed and non-completed sites track to this AWO, meaning that since it is not yet completed, Staff should use the $13.2 million forecast according to their methodology.

Q. What is PGE's recommendation regarding this project?

A. PGE recommends that the commission reject Staff's proposal regarding the DPF Project. The installation of these filters is essential to keep PGE's CRO capacity to serve customers, and PGE intends to complete its plan for 2024 as laid out in the May 1 plant update. If these filters are not installed, DSG fleet capacity would be reduced, and to meet NERC standards, that reduction would have to be served from somewhere else in PGE's generation fleet, which would reduce the overall amount of generation that PGE can serve to customers.

VI. Fleet Capital

Q. Please describe PGE's fleet and the fleet forecasted capital additions for 2024.

A. PGE's fleet includes the different vehicles that we utilize in a variety of roles to serve our customers and includes passenger vehicles, service vehicles, bucket trucks, off-road vehicles, and forklifts. Our forecasted amounts for capital additions related to fleet vehicles for 2024 is $12,684,278.

Q. Please describe Staff's testimony and proposed adjustments related to PGE's fleet.

A. Staff proposes adjustments to PGE's fleet request in three areas: (1) premature replacement of fleet vehicles, (2) the electrification of our own vehicles, and (3) imprudent vehicle configurations. Staff also proposes to permanently remove $2.4 million related to electric vehicle (EV) purchases related to a black box settlement which was a part of UE 416.

Q. Please describe Staff's proposed adjustment related to their claim of premature vehicle replacements.

A. Staff proposes a downward adjustment of $5.8 million related to the premature replacement of vehicles. In a Data Request response, Staff stated that vehicles were determined to be prematurely replaced if in PGE's Response to Data Requests No. 324 and 325 a vehicle's reason for disposal was listed as simply "Fully Depreciated."[33]

Q. Is Staff utilizing the correct data set in their work?

A. No. Staff is using PGE's response to OPUC Data Request 325 to determine which vehicles PGE is retiring in 2024. However, PGE's response to that data request supplies PGE's vehicle retirements in the 2025 year as requested. To be clear, capital additions in this case do not

[33] Exhibit PGE 1703, Staff's Response to PGE Data Request No. 004.

consider vehicles being retired in the 2025 year. Exhibit 1704 provides an electronic spreadsheet showing the retiring vehicles and their replacements in the relevant year 2024.

Q. What is PGE's methodology for determining when a vehicle needs to be replaced?

A. PGE determines that vehicles have reached the end of their useful life by viewing each individual vehicle comprehensively; considering age, both mileage and hours of operation (with each hour being equated to an additional 30 miles of use), job function, parts availability, and general economics of owning a vehicle. In short, to manage our fleet we must make a series of judgments to determine whether a vehicle should be kept, disposed of, or repurposed. Exhibit 1704 provides a description of the determining factors PGE used to determine why each vehicle is to be disposed of.

Q. Are there other reasons that a vehicle may need to be replaced?

A. Certain vehicles in our fleet cannot be kept due to changes in law, such as diesel emissions controls. HB 2007 set diesel emission standards for medium and heavy-duty trucks. There are no less than 14 diesel vehicles that PGE is replacing in 2024 at least in part for the purposes of compliance with HB 2007, as shown in Exhibit 1704. PGE considered retrofitting these vehicles for compliance purposes, but it was determined to be economically unviable due to the age of the vehicles.

Q. Please describe Staff's proposed adjustment related to the purchase of electric vehicles (EVs).

A. Staff proposes a downward adjustment of $325 thousand related to their calculated net EV premium, that is the additional expense of purchasing and maintaining an EV versus an internal combustion engine (ICE) vehicle.

Q. Please respond to Staff's proposed adjustment related to the purchase of EVs.

A. As shown in Staff's Exhibit 2206, $386 thousand dollars of this proposed adjustment is related to vehicles because Staff assumes there will be no fuel savings, O&M savings, or tax credits. When analysis includes these additional elements, the result is $59 thousand of *savings*. In short, when Staff includes cost savings in their analysis, they show that PGE saves money with EVs. Conversely, when Staff does not include the cost savings of transitioning to EVs, they show that PGE pays a premium to purchase EVs. While PGE does recognize that many of the vehicles in Staff's analysis are not eligible for tax credits, ICE off-road vehicles and forklifts have additional O&M expenses that are not captured in Staff's analysis.

Not only are there costs saving when considering the full comparison, but PGE believes that replacing carbon-emitting vehicles where possible is the right thing to do for our customers and community and is one more step toward achieving a clean energy future.

Q. Please describe Staff's proposed adjustment related to imprudent vehicle configurations.

A. Staff proposed an adjustment of $120,000 related to imprudent vehicle configurations. When asked in a Data Request, Staff was able to confirm that those vehicle configurations they determined were imprudent related to Jobsite Energy Management Systems (JEMS) that were installed on certain vehicles in PGE's fleet, resulting in an additional expense of $120,000 over the alternative.[34]

Q. What is JEMS?

A. JEMS is a system that includes both a battery and a management system that allows for PGE's service vehicles to operate aerials, jobsite tools, auxiliary lighting systems, and provide crews

[34] PGE Exhibit 1705, Staff's Response to PGE Data Request No. 005.

AC or heat during weather events without utilizing an ICE as a generator. This produces fuel cost savings and prevents unnecessary emissions without compromising the vehicle's ability to manage those functions utilizing the ICE when needed.

Q. How does PGE respond to this characterization of the JEMS equipment?

A. PGE contends that this is a prudent configuration for multiple reasons: (1) safety, (2) permitting and compliance, and (3) significantly less idling time.

JEMS allows for a safer work environment because crews that can hear better, can then communicate better and are more aware of their surroundings. Without a JEMS installed, the vehicles ICE must be running and operating as a generator in order for the aerial to function, so the line crews that are most effected by ICE related noise are those who have the most dangerous jobs.

Some localities, including the City of Portland, do not allow work vehicles to idle during night-time hours as to not disturb residents' sleep. Portland City Code, Chapter 18.12.020 parts A and B relate directly to PGE's work. JEMS allows PGE to be in compliance in these instances, as JEMS operates at sound levels well below thresholds established in ordinances like these.

When PGE line crews arrive at a jobsite without a JEMS unit, they must run the ICE to operate their equipment. This leads to excess wear and tear on vehicles, where each additional hour of idling equals approximately 30 miles of driving, and excess use of fuel as well as sending unnecessary emissions into neighborhoods and our atmosphere.

Q. Please describe Staff's proposed adjustment related to the UE 416 black box settlement.

A. Staff proposes to permanently remove $2.4 million from PGE's rate base related to the purchase of EVs that were settled in a black box settlement in UE 416.

Q. How does PGE respond?

A. PGE notes that these purchases were made in alignment with Oregon Governor's Executive Order 2020-04 which establishes "science-based GHG reduction goals."[35] Although the executive order does not specifically direct utilities to invest in electrification of their own fleets, PGE's investment in electrification of its fleet aligns with the state's goals of reducing GHG emissions. The executive order does include specific direction to the OPUC to encourage "electric companies to support TE infrastructure that supports GHG reductions, helps achieve the TE goals set forth in SB 1044 and is reasonably expected to result in long-term benefit to customers. Staff's application of narrow cost benefit analysis applied to transportation electrification investments made by the company is concerning and ignores the long-term benefits of this transition to customers. This inconsistent application of law and policy is baffling and seems to suggest a standard different for utility investments to address transportation greenhouse gas abatement when the investment benefits utility operations.

Q. Please summarize PGE's stance on Staff's testimony and proposed adjustments to fleet expenditures in 2024.

A. PGE requests that the Commission reject Staff's proposed adjustments related to fleet expenditures. PGE invests in and maintains a prudent portfolio of working vehicles that enable us to complete critical tasks and maintain our grid for our customers. Staff's analysis was based on erroneously selected data, an incomplete picture of cost savings associated with EVs, and without consideration to the value of JEMS systems.

[35] Office of the Governor, State of Or., Exec. Order 2020-04 at 8 (March 10, 2020). https://www.oregon.gov/gov/eo/eo_20-04.pdf

VII. Associated Energy Storage

Q. What is PGE's proposal regarding the definition of "associated energy storage" in this filing?

A. In PGE Exhibit 500, we proposed that the Commission adopt the following definition for associated storage: "all co-located energy storage and standalone storage connected at the transmission-voltage level that is used to integrate, firm or shape renewable energy sources."[36] Specifying that standalone energy storage resources used to firm and shape renewable resources are "associated energy storage" for purposes of the renewable automatic adjustment clause (RAAC) is intended to give energy storage resources acquired for integrating and firming renewables equal treatment in the RAAC, whether co-located with renewable energy resources or a standalone storage resource.

Q. Are you continuing to pursue your proposal on this topic?

A. No. In order to narrow the issues and be responsive to the feedback of parties in this proceeding, we are electing to withdraw this proposal.

Q. Is there any testimony from the Parties that PGE would like to address.

A. Yes, we would like to address the concerns raised regarding PGE decision to renew this proposal, as if a definitive resolution on this matter has been achieved in the past. We take particular note of the Citizens' Utility Board's (CUB) request to "reject this proposal *again* [emphasis added]," which is an inaccurately stated request since this issue has never been formally rejected or ruled upon by the Commission. Further, PGE's willingness to engage in

[36] PGE/500, Felton/33.

good-faith negotiations and pursue reasonable settlements in other proceedings is an unfair suggestion that this matter has ever been definitively resolved, as implied by AWEC.[37]

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[37] AWEC/100, Mullins/72.

VIII. Qualifications

Q. Ms. Powell, please summarize your qualifications.

A. I received my Bachelor of Science in General Science from the United States Naval Academy. I joined PGE as the Vice President of Utility Operations in May 2024. Over my 30-year career, I have held numerous leadership roles directing thermal, solar, hydro generation and Electric Asset Management in the US Navy, Lower Colorado River Authority (LCRA) and at Pacific Gas & Electric (PG&E).

Q. Mr. Clark, please summarize your qualifications.

A. I received my Bachelor of Science in Mechanical Engineering from the University of Washington. I joined PGE as a mechanical engineer at Trojan Nuclear Plant in 1989. Over my 35-year career at PGE I have held numerous management roles directing thermal, wind, and hydro generation and engineering, and was a director in information technology. I am currently the Senior Director of Thermal Generation and Planning as of January 2022.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1701HC	Highly Confidential Staff Data Request Response 171-A
1702HC	Highly Confidential Staff Data Request Response 173-A
1703	Staff's Response to PGE Data Request No. 004
1704	Fleet Workpaper
1705	Staff's Response to PGE Data Request No. 005

UE 435

Exhibit 1701 contains highly confidential information and is subject to Modified Protective Order 24-062

Exhibit 1701 has been retained in its native format

UE 435

Exhibit 1702 contains highly confidential information and is subject to Modified Protective Order 24-062

Exhibit 1701 has been retained in its native format

Date: August 2, 2024

TO:
Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC-0306
Portland, OR 97204

FROM: Eric Shierman, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 435 – PGE Data Request No. 4

PGE Data Request No. 4:

Reference Staff/ 2200/16, lines 6-9. Please explain Staff's criteria for determining which vehicle purchases are premature and "may have been delayed past the end of the test year."

OPUC Data Response No. 4:

Staff's criterion was documentation of the vehicle(s) needed to be replaced based on PGE's responses to OPUC DRs 324 and 325. Staff identified "Fully Depreciated" as lacking evidence a vehicle needed to be replaced.

2024 Vehicle Purchases			Vehicle to be disposed of, if applicable					
Make	Model	Vehicle Cost	Turn In Unit Type	Miles	Hours	Actual Calculated Miles	Is Unit Disposed as of 7/23/24?	Reason for Disposal
Ford	F550	$140,000.00	1995 CHEV 3500 6.5L 4X4 FLATBED 4X4 REG CAB	55,515	1,997	115,425	No	Manufacturer no longer makes replacement parts for something this old
International	HX520 SFA 6X4	$552,988.00	2010 Intern 7400 SBA MANLIFT 6X4 55FT JIB TERE	122,368	12,034	483,388	Yes	14+ years is fully depreciated, miles + hours = extremely high miles and risk for major failure
Toyota Lift	8FBE20U	$51,883.00	011 TOYOTA LIFT 8FGU25 CONSTRUCTION FORKLI	0	524	15,720	Yes	Shelving configuration changed making too big for application
Ford	Transit Van	$104,313.26	2012 Freig Sprinter VAN CARGO 4X2	143,110	0	143,110	No	12+ years is fully depreciated, miles + estimated hours = extremely high risk of major component failure
Chevrolet	EQUINOX EV	$47,718.75	2012 FORD TRANSIT 2.0L 4X2	152,545	0	152,545	No	12+ years is fully depreciated, miles + estimated hours = extremely high risk of major component failure
John Deere	50 P-TIER	$109,279.35	2 BOBCAT E50 47.9 HPD CONSTRUCTION EXCAVA	0	2,162	64,860	Yes	Equipment was stolen
Chevrolet	2500HD	$82,408.00	2013 CHEV 1500 5.3L 4X4 CRW CAB	144,288	0	144,288	No	11+ years is fully depreciated, high mileage, manufacturer no longer makes parts
Chevrolet	2500HD	$52,007.68	2013 CHEV 1500 5.3L 4X4 EXT CAB	157,853	0	157,853	No	11+ years is fully depreciated, very high mileage, manufacturer no longer makes replacement parts
Toyota Lift	05-8FBM40T	$100,883.00	13 TOYOTA LIFT 7FGKU40 CONSTRUCTION FORKL	0	1,629	48,870	No	Shelving configuration changed making too small for application; reassignment was not a viable solution
Ford	Transit Van	$104,313.26	2014 Freig Sprinter VAN CARGO 4X2	200,000	0	200,000	No	10+ years and 200k miles is fully depreciated and high risk for major component failure
Chevrolet	1500 EV	$82,277.05	2014 CHEV 2500HD 6.0L 4X4 REG CAB	163,956	0	163,956	No	10+ years and high miles is fully depreciated and high risk for major component failure with limited part availablity
Chevrolet	EQUINOX EV	$47,718.75	2014 FORD ESCAPE 1.6L 4X4	145,509	0	145,509	No	10+ years and high miles is fully depreciated, repair costs trending upward
Ford	F600	$73,762.45	15 FORD F550 6.8L 4X4 SERVICE BODY 4X4 REG C	152,659	7,138	366,799	No	Should be on an 8 year lifecycle, very heavy use, is fully depreciated based on mileage
Freightliner	M2106 with Bucket	$400,685.00	2015 Inter 7500 SBA MANLIFT 6X4 72FT ALTEC	32,288	5,574	199,508	No	Reassigned
Toyota Lift	05-9FBM25T	$82,343.00	009 TOYOTA LIFT 8FGU25 CONSTRUCTION FORKLI	0	4,659	139,770	No	Weight needs increased making under capacity, fully depreciated in age
Chevrolet	2500HD	$82,408.00	2015 CHEV 1500 5.3L 4X4 CRW CAB	129,974	0	129,974	No	10+ years and high miles is fully depreciated and high risk for major component failure
Chevrolet	2500HD	$82,408.00	2015 CHEV 2500HD 6.0L 4X4 CRW CAB	89,545	0	89,545	No	Reassigned
Chevrolet	2500HD	$52,007.68	2015 CHEV 2500HD 6.0L 4X4 DBL CAB	181,535	0	181,535	No	Fully depreciated in age, extremely high mileage, high risk for major component failure
John Deere	GATOR TE	$16,915.23	POLARIS GEM NEIGHBORHOOD ELECTRIC VEHICL	7,340	0	7,340	Yes	Value of equipment < cost to repair
John Deere	GATOR TE	$16,915.23	POLARIS GEM NEIGHBORHOOD ELECTRIC VEHICL	5,540	0	5,540	Yes	Value of equipment < cost to repair
Ford	Transit Van	$104,313.26	2016 Freig Sprinter VAN CARGO 4X2	225,259	0	225,259	No	Fully depreciated in extremely high miles and risk of major component failure
Chevrolet	1500 EV	$82,277.05	2016 CHEV 1500 4.3L 4X4 CRW CAB	149,297	6,892	356,057	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Chevrolet	2500HD	$55,704.36	2017 CHEV 1500 4.3L 4X4 DBL CAB	144,205	5,965	323,155	Yes	Fully depreciated in miles + hours = very high and risk of major compont failure

Chevrolet	1500 EV	$82,277.05	2017 CHEV 1500 4.3L 4X4 DBL CAB	202,709	10,112	506,069	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Chevrolet	1500 EV	$82,277.05	2017 CHEV 1500 4.3L 4X4 DBL CAB	190,387	9,151	464,917	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Chevrolet	2500HD	$52,007.68	2017 CHEV 1500 4.3L 4X4 DBL CAB	131,459	2,544	207,779	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Chevrolet	1500 EV	$82,277.05	2017 FORD F150 2.7L 4X4 SPR CAB	95,495	3,574	202,715	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Chevrolet	1500 EV	$82,277.05	17 FORD F150 2.7L 4X4 SPR CAB	207,228	8,148	451,668	No	Manufacturer defect of cracking frames. Was orignally repaired under warranty and out of service for several months. Failure is reoccuring, vehicle is out of warranty. Cost and time out of service is too high.
Chevrolet	3500HD Service Body	$115,628.72	2017 FREIG SPRINTER 3.0L 4X4 VAN CARGO	196,330	0	196,330	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Chevrolet	3500HD Service Body	$115,628.72	2017 FREIG SPRINTER 3.0L 4X4 VAN CARGO	203,984	0	203,984	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Chevrolet	3500HD	$53,961.36	2017 CHEV 2500HD 6.0L 4X4 DBL CAB	186,337	6,194	372,157	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Chevrolet	3500HD Service Body	$115,628.72	2017 Chevy 3500HD SERVICE BODY 4X4 REG CAB	154,041	8,608	412,281	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Ford	F550	$140,000.00	2017 FORD F550 6.8L 4X4 FLATBED 4X4 SPR CAB	181,283	10,192	487,043	No	Fully depreciated in miles + hours = very high and risk of major compont failure
Chevrolet	2500HD	$82,408.00	2018 CHEV 1500 4.3L 4X4 CRW CAB	75,395	5,519	240,965	No	*Unit repurposed to another line center / Employee job scope changed and vehicle needs changed too
Chevrolet	EQUINOX EV	$47,718.75	2019 CHEV EQUINOX 1.5L AWD	108,368	0	108,368	No	*Unit repurposed to another line center / Employee job scope changed and vehicle needs changed too
Chevrolet	2500HD	$82,408.00	2019 CHEV COLORADO 3.6L 4X4 EXT CAB	50,741	5,418	213,281	No	*Unit repurposed to another line center / Employee job scope changed and vehicle needs changed too
Chevrolet	2500HD	$82,408.00	2019 CHEV 1500 4.3L 4X4 CRW CAB	57,335	5,320	216,935	No	*Unit repurposed to another line center / Employee job scope changed and vehicle needs changed too
John Deere	GATOR TE	$16,915.23	POLARIS GEM NEIGHBORHOOD ELECTRIC VEHICL	2,375	1,053	33,965	No	Value of equipment < cost to repair
International	MV607 SBA LP	$173,811.02	2001 INTER 4700 LPT 444E 4X2 VAN BOX 4X2	17,447	114	20,867	No	*Unit stored parts at substation so low miles / Age of unit does not allow to order new parts, etc... diesel emissions too
Ford	F550	$140,000.00	4 FORD F550 6.0L 4X4 CUSTOM FLATBED 4X4 REG	104,528	9,803	398,618	No	*Age of unit does not allow for parts, etc... Unit was an old converted Hoopie, diesel emissions too
Ford	F550 with Bucket	$185,288.84	2004 Inter SBA LAMPER 4X2 36FT TEREX	163,064	14,794	606,884	No	20+ years and extremely high miles; must be taken out of service due to diesel emission regulations
Toyota Lift	05-9FBM30T	$87,287.00	CATERPILLAR P6000 63HPU CONSTRUCTION FOR	0	3,409	102,270	No	Upgrading to accommodate necessary capacity changes
Ford	F550	$63,410.70	5 FORD F550 6.0L 4X4 CUSTOM FLATBED 4X4 REG	94,551	9,570	381,651	No	*Age of unit does not allow for parts, etc... Unit was an old converted Hoopie, diesel emissions too

Chevrolet	2500HD	$82,408.00	2006 FORD F550 6.0L 4X4 HOOPIE REG CAB	99,211	2,594	177,031	No	*Age of unit does not allow for parts, etc... diesel emissions too
John Deere	75 P-TIER	$171,169.31	2005 INGER 341G CONSTRUCTION EXCAVATOR	0	4,535	136,050	No	Age and hours = fully depreciated, needed increase in capacity
Chevrolet	EQUINOX EV	$47,718.75	2006 CHEV TRAILBLAZER 4.2L 4X4	135,055	0	135,055	No	*Age of unit does not allow for parts, etc... Fleet no longer supports this model of vehicle
Ford	F550	$140,000.00	5 FORD F550 6.0L 4X4 CUSTOM FLATBED 4X4 REG	85,815	9,999	385,785	No	*Age of unit does not allow for parts, etc... Unit was an old converted Hoopie, diesel emissions too
Ford	F550	$140,000.00	2006 FORD F550 6.0L 4X4 HOOPIE 4X4 REG CAB	111,357	646	130,737	No	*Age of unit does not allow for parts, etc... diesel emissions too
John Deere	135 P-Tier	$282,341.61	006 JOHN DEERE 120C CONSTRUCTION EXCAVATC	0	2,394	71,820	No	Upgrading to accommodate necessary capacity changes
Toyota Lift	05-9FBMK20T	$79,832.00	CATERPILLAR P3500G 54HPU CONSTRUCTION FOI	0	4,248	127,440	No	Upgrading to accommodate necessary capacity changes
Ford	F550	$140,000.00	2007 FORD F550 6.0L 4X4 HOOPIE 4X4 REG CAB	159,781	10,000	459,781	No	*Age of unit does not allow for parts, etc... diesel emissions too
Ford	F550 Service Body	$131,547.41	07 FORD F550 6.0L 4X4 SERVICE BODY 4X4 REG C	137,000	6,587	334,610	No	*Age of unit does not allow for parts, etc... diesel emissions too
International	MV607 SBA LP	$173,811.02	2008 INTER 4300 SBA MAXX DT 4X2 VAN BOX 4X2	141,368	5,226	298,148	No	Age and miles+hours = fully depreciated
International	HX520 SFA 6X4	$552,988.00	2007 Inter 7600 SBA DERRICK 6X4 80FT TEREX	91,188	12,075	453,438	No	*Age of unit does not allow for parts, etc... diesel emissions too
International	HX520 SFA 6X4	$552,988.00	2007 Inter 7600 SBA DERRICK 6X4 65FT TEREX	80,255	10,317	389,765	No	*Age of unit does not allow for parts, etc... diesel emissions too
Ford	F600 with Bucket	$232,967.04	2007 Inter 4300 SBA MANLIFT 4X2 40FT TEREX	111,286	8,655	370,936	No	*Age of unit does not allow for parts, etc... diesel emissions too
Toyota Lift	05-8FBM45T	$103,694.00	007 TOYOTA LIFT 3808P CONSTRUCTION FORKLIF	0	2,169	65,070	No	Upgrading to accommodate necessary capacity changes
Trail King	TKT50LP	$57,254.89	2007 TRAIL KING TKT40LP TRAILER EQUIPMENT	0	0	0	No	*Upgrade trailer to accomidate new sized equipment
Ford	F600	$134,000.00	008 DODGE 5500 6.7L 4X4 FISH TRUCK 4X4 REG C/	91,050	0	91,050	No	*Age of unit does not allow for parts, etc... diesel emissions too- Fish Truck, needing tank upgrades to be in compliance with fish needs
Ford	F600	$134,000.00	008 DODGE 5500 6.7L 4X4 FISH TRUCK 4X4 REG C/	98,037	0	98,037	No	*Age of unit does not allow for parts, etc... diesel emissions too- Fish Truck, needing tank upgrades to be in compliance with fish needs
Ford	F550	$140,000.00	DODGE 5500 6.7L 4X4 CUSTOM FLATBED 4X4 RE(	112,297	12,029	473,167	No	*Age of unit does not allow for parts, etc... Unit was an old converted Hoopie, diesel emissions too
Ford	F600 with Bucket	$194,545.12	2008 Inter 4300 SBA MANLIFT 4X2 40FT TEREX	172,738	12,693	553,528	Yes	*Age of unit does not allow for parts, etc... diesel emissions too
Ford	F600 with Bucket	$194,545.12	2008 Inter 4300 SBA MANLIFT 4X2 40FT TEREX	122,281	9,216	398,761	No	*Age of unit does not allow for parts, etc... diesel emissions too
Polaris	Ranger	$46,516.88	2008 KUBOTA RTV900 CONSTRUCTION UV	0	366	10,980	Yes	*Age of unit does not allow for parts, etc...
Chevrolet	EQUINOX EV	$47,718.75	2009 Chevy 3500HD PICKUP 4X4 REG CAB	144,752	0	144,752	No	*Age of unit does not allow for parts, etc...
Chevrolet	EQUINOX EV	$47,718.75	2009 Chevy 3500HD PICKUP 4X4 REG CAB	144,752	0	144,752	No	*Age of unit does not allow for parts, etc...
Chevrolet	3500HD	$52,886.27	2009 Chevy 3500 PICKUP 4X4 REG CAB	140,187	0	140,187	No	*Age of unit does not allow for parts, etc...
Toyota Lift	05-8FBM45T	$108,718.00	09 TOYOTA LIFT 7FDKU40 CONSTRUCTION FORKL	0	1,273	38,190	No	Upgrading to accommodate necessary capacity changes

Cascade	7X16 T/A TILTBED	$8,947.50	2009 MAX HENDRIX 6TP TRAILER	0	0	0	Yes	*Age of unit does not allow for parts, etc... upgraded trailer to accomidate new sized equipment
Polaris	Ranger	$46,516.88	2008 POLARIS A08MN50AF CONSTRUCTION ATV	0	0	0	Yes	*Age of unit does not allow for parts, etc...
Cascade	7X16 T/A TILTBED	$8,947.50	1996 BUTLER BP500SA POLE TRAILER	0	0	0	Yes	*Age of unit does not allow for parts, etc... upgraded trailer to accomidate new sized equipment
John Deere	333G	$166,135.55	96 BOBCAT 873 73HPD CONSTRUCTION SKID STE	0	920	27,600	No	*Age of unit does not allow for parts, etc...
Chevrolet	EQUINOX EV	$47,718.75	1997 CHEV 1500 5.3L 4X4 REG Cab	131,525	0	131,525	No	*Age of unit does not allow for parts, etc...
Toyota Lift	8FBM50T	$120,046.00	CATERPILLAR GP40 97HPU CONSTRUCTION FOR	0	2,542	76,260	No	Upgrading to accommodate necessary capacity changes
International	MV607 SBA LP	$173,811.02	2000 INTER 4700 LPT 444E 4X2 VAN BOX 4X2	79,797	3,999	199,767	Yes	*Age of unit does not allow for parts, etc... diesel emissions too
Ford	F550 with Bucket	$185,288.84	2002 Inter 4300 SBA LAMPER 4X2 37FT VERSALIFT	200,951	21,972	860,111	Yes & No	22+ years + over 850k miles is fully depreciated and at extremely high risk of major component failure with zero options for replacement parts.
Toyota Lift	05-8FBM50T	$124,426.00	2004 CATERPILLAR GP40K 97HPU CONSTRUCTION FORKLIFT & 2015 TOYOTA LIFT	0	2,177	65,310	No	*New unit allowing location to retire 2 old units
Chevrolet	3500HD	$97,509.21	2006 Chevy 3500 FLATBED 4X4 REG CAB	60,128	0	60,128	No & No	*Age of unit does not allow for parts, etc... Unit is for a salt spreader, salt spreading equiment falling apart
Toyota Lift	05-9FBM35T	$91,042.00	2008 TOYOTA LIFT 8FGU25 CONSTRUCTION FORKLIFT & 2015 TOYOTA LIFT 8.FGU32U	0	2,291	68,730	N	*New unit allowing location to retire 2 old units
Chevrolet	2500HD	$58,678.71	2009 CHEV COLORADO 2.9L 4X4 EXT CAB & 2009 CHEV COLORADO 2.9L 4X4 EXT CAB	167,954	0	167,954	Yes & Yes	Age+miles = fully depreciated TWO vehicles retired and replaced with one
RANDCO	24-FIRE	$35,680.49	ADD	N/A	N/A	N/A	N/A	Equipment adds for wildfire mitigation
RANDCO	24-FIRE	$35,680.49	ADD	N/A	N/A	N/A	N/A	Equipment adds for wildfire mitigation
RANDCO	24-FIRE	$35,680.49	ADD	N/A	N/A	N/A	N/A	Equipment adds for wildfire mitigation
RANDCO	24-FIRE	$35,680.49	ADD	N/A	N/A	N/A	N/A	Equipment adds for wildfire mitigation
RANDCO	24-FIRE	$35,680.49	ADD	N/A	N/A	N/A	N/A	Equipment adds for wildfire mitigation
RANDCO	24-FIRE	$35,680.49	ADD	N/A	N/A	N/A	N/A	Equipment adds for wildfire mitigation
Chevrolet	1500 EV	$82,277.05	ADD	N/A	N/A	N/A	N/A	*Turn in vehicle repurposed to another group
Genie	GTH-844	$157,700.00	ADD	N/A	N/A	N/A	No	*Turn in repurposed to another group, operational needs of RC changed, and fit needs of another RC
Toyota Lift	05-8FBM45T	$106,957.00	ADD	N/A	N/A	N/A	No	*Upgrade forklift to accommodate larger capacity needed
Trail King	TKT40LP	$47,729.68	ADD	N/A	N/A	N/A	N/A	*Trailer needed to be added to accommodate new unit
NA	NA	NA	2004 INTER SBA FLATBED	21,262	0	21,262	Yes	Underutlized not replaced
NA	NA	NA	INTER 7300 SFA 2010 MAXXDT 4X4	15,873	776	24,056	Yes	Underutlized not replaced
NA	NA	NA	CHEV ASTRO 2005 4.3L AWD	66,546	0	0	Yes	Underutlized not replaced
NA	NA	NA	CHEV 3500HD 1995 7.4L 4X2	30,718	0	0	Yes	Underutlized not replaced
NA	NA	NA	CHEV 3500HD 2010 6.0L 4X2	127,989	0	0	Yes	Underutlized not replaced
NA	NA	NA	INTER 4300 SBA 2007 DT466E 4X2	91,949	1,465	45,415	Yes	Underutlized not replaced
NA	NA	NA	INTER 4300 SBA 2008 MAXXDT 4X2	172,738	12,693	393,483	Yes	Underutlized not replaced
NA	NA	NA	FREIG SPRINTER 2016 3.0L 4X4	92,500	0	0	Yes	Underutlized not replaced
NA	NA	NA	CHEV 4500HD 2016 6.0L 4X2	87,569	0	0	Yes	Underutlized not replaced
NA	NA	NA	CHEV 4500HD 2016 6.0L 4X2	91,943	0	0	Yes	Underutlized not replaced
NA	NA	NA	CHEV 4500 2017 6.0L 4X2	118,250	0	0	Yes	Underutlized not replaced

Date: August 2, 2024

TO:
Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC-0306
Portland, OR 97204

FROM: Eric Shierman, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 435 – PGE Data Request No. 5

PGE Data Request No. 5:

Reference Staff/2200/16, lines 3-5. Please confirm that Staff's proposed adjustment relates to PGE electing to outfit certain vehicles with JEMS systems. If not, please explain what the "imprudent configurations" of vehicles are, and describe how Staff determined the prudence of these configurations.

OPUC Data Response No. 5:

Confirmed. Staff only found the JEMS system as an imprudent configuration in that category of Staff adjustment.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Josh Figueroa
Christopher Liddle

August 14, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Christopher A. Liddle. I am the Senior Director, Risk Management and Assistant Treasurer at PGE. My qualifications can be found at the end of PGE Exhibit 600.

My name is Josh Figueroa (he/him/his), and I am a Senior Associate of The Brattle Group, whose business address is One Beacon Street, Suite 2600, Boston, Massachusetts, 02108. I provided direct testimony in UE 435 in February of this year. I directly sponsored the testimony found in Section IV of Exhibit 600, and I am directly sponsoring the testimony in Section III of this Exhibit 1800. My qualifications can be found in PGE Exhibit 603.

Q. What is the purpose of your testimony?

A. Our testimony supports PGE's proposed cost of capital and capital structure for the 2025 Test Year. PGE's cost of capital, capital structure, and cost of debt were last approved in Public Utility Commission of Oregon (Commission) Order No. 23-386 in October 2023.

We explain that PGE's requested cost of capital and capital structure are necessary to support its credit profile for access to low-cost debt and equity markets, to fund its capital investments planned for 2025 and beyond, and to provide PGE the opportunity to earn a fair return on equity for shareholders while keeping its costs reasonable for customers.

Mr. Figueroa will continue to support PGE's position that a higher return on equity (ROE) than currently authorized is warranted given existing market dynamics, though PGE has reduced its proposal from 9.75% to 9.65%.

Mr. Liddle will address Staff (Staff) of the Public Utility Commission of Oregon (OPUC) and the Alliance of Western Electric Consumer (AWEC) testimony regarding PGE's capital structure and Staff's testimony on PGE's cost of long-term debt.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II – Overview & Summary
- Section III – Return on Equity
- Section IV – Capital Structure
- Section V – Cost of Debt
- Section VI – Qualifications

II. Overview and Summary

Q. Please provide an overview of your position on ROE.

A. PGE submitted this general rate review with an initial return on equity (ROE) request of 9.75%, which aligns with the average ROE granted in rate cases across the industry over the past two years. In an effort to work collaboratively with stakeholders, maintain a lens on affordability and reduce the overall price request in this case, and narrow the issues in this proceeding, we have revised our ROE request to 9.65%. Although this figure exceeds our currently authorized ROE of 9.5%, we believe a moderately higher ROE is warranted given the current economic environment characterized by higher interest rates.

Q. Given that PGE's cost of capital was last approved in October 2023, does PGE see this as a relitigation of ROE, as suggested by parties to this proceeding?

A. We disagree that requesting a new Return on Equity (ROE) in this case constitutes a 'relitigation.' The underlying facts and circumstances that led to the determination of a 9.5% ROE in Docket UE 416 (UE 416) have undergone significant changes since that decision. The Parties have acknowledged this change in PGE's average cost of debt, which was settled at 4.485% in UE 416. PGE filed for a new average cost of debt of 4.628%, driven by evolving market conditions, and several months later, Staff's opening testimony recognized that the average cost of debt has already increased to 4.641%. It would be inconsistent to claim that PGE is seeking inappropriate 'relitigation' of the ROE while simultaneously acknowledging and accepting the need to adjust the cost of debt to reflect current market realities. The ROE and the cost of debt are linked, and both must be reevaluated in light of the dynamic economic environment.

It is also worth noting that PGE engaged in annual, consecutive rate cases for the test years 2014, 2015, and 2016. In each of these proceedings, the parties were willing to litigate the ROE in light of the prevailing decreasing interest rate environment. Specifically, in the 2014 test year, the ROE was reduced from the previously authorized 10% to 9.75%. In the 2015 test year, it further decreased to 9.68%, and in the 2016 test year, it dropped to 9.6%.

However, now that we find ourselves in a rising interest rate environment, some parties are expressing concerns over PGE's request for a reevaluation of the ROE, characterizing it as an attempt to "relitigate" the matter. This stance appears to be inconsistent with parties' previous willingness to adjust the ROE in response to changing market conditions from one year to the next.

It is essential to approach this matter objectively and consistently, recognizing that both decreasing and increasing interest rates can necessitate a review of the ROE to ensure fair and reasonable prices.

Q. Please provide an overview of your position on capital structure.

A. We continue to believe that a 50% debt / 50% equity ratio is appropriate. Our 50-50 capital structure recommendation is supported by utility industry peer data—a valuable resource that provides a benchmark for the standard amount of financial risk that is reasonable within the utility industry. In addition, the equity portion helps offset the leverage and risk that PGE will likely encounter over the next few years and a capital structure at 50% equity and 50% debt helps offset the leverage imputed by the rating agencies on PGE’s purchased power. In Section IV, Mr. Liddle will review Staff and AWEC’s testimony on capital structure and provide additional support for why a 50-50 ratio is appropriate for PGE’s 2025 Test Year.

Q. What is your positions on the weighted cost of debt?

A. Staff has recommended a weighted cost of debt of 4.641%, based on a more recent analysis of debt market conditions relative to the time when PGE filed this rate review. We concur that the most up-to-date and relevant data should be utilized in determining the weighted cost of debt, and we agree to the proposed adjustment.

Q. What is PGE's recommended cost of capital for the 2025 Test Year?

A. PGE is updating its recommended cost of capital for the 2025 Test Year to reflect our revised ROE proposal of 9.65% and adopt Staff's cost of debt of 4.641%. As such, PGE's recommended cost of capital is now 7.146%, which also reflects PGE's proposed capital structure of 50% debt and 50% equity. Table 1 shows the recommended cost of the components of PGE's capital, common equity, and long-term debt, and PGE's requested 2025 regulatory capital structure.

Table 1
PGE's Weighted Cost of Capital
Test Year 2025

Component	Average Outstanding ($000)[1]	Percent of Capital[2]	Component Cost	Weighted Cost
Long-term Debt	$4,738,800	50%	4.641%	2.321%
Common Equity	$4,183,009	50%	9.650%	4.825%
Total	**8,921,809**	**100%**		**7.146%**

[1] "Average Outstanding" reflects PGE's projected average values of long-term debt and common equity for 2025.
[2] "Percent of Capital" reflects PGE's long-term targeted regulatory capital structure of 50% debt, 50% equity, and is used to calculate PGE's weighted average cost of capital (Weighted Cost)."

III. Return on Equity

A. Introduction

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked to review and comment on the Opening Testimony of Mr. Matt Muldoon of the Staff of the OPUC as it pertains to the return on equity (ROE) for Portland General Electric Company (PGE or the Company).[3] I have also been asked to respond to the Opening Testimony of Mr. Lance D. Kaufman on behalf of the AWEC;[4] the Opening Testimony of Lisa V. Perry on behalf of Walmart Inc. (Walmart);[5] and Mr. Bob Jenks on behalf of the Citizen's Utility Board (CUB)[6] (collectively, the Parties) as each of these testimonies pertain to the allowed ROE for PGE. I also address specific arguments in the Opening Testimony of Mr. Russ Beitzel on behalf of OPUC Staff as they pertain to business risk and PGE's allowed ROE.[7]

Q. Is there anything in Staff's or the Parties' testimonies that caused you to change your recommendations regarding Portland General's return on equity?

A. No. Having reviewed the opening testimonies of Staff and the Parties I continue to find that my recommended ROE range of 10.25% to 11.25% (midpoint 10.75%) for PGE and the Company's requested allowed ROE of 9.75% on a 50% equity capital structure remains reasonable.[8] This finding also takes into consideration changes in capital market conditions since the filing of my Direct Testimony. However, I understand that PGE has made a

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[3] Staff/400, Muldoon.
[4] AWEC/200, Kaufman.
[5] Walmart/100, Perry.
[6] CUB/100, Jenks.
[7] Staff/100, Beitzel
[8] PGE/600, Figueroa-Liddle/17.

managerial decision given the totality of facts and circumstances in this particular rate proceeding to reduce its request from 9.75% to 9.65%.

Q. Please summarize your testimony:

A. Having reviewed the testimonies of Staff, Dr. Kaufman, Ms. Perry, and Mr. Jenks, I find the following:

- Staff's, Dr. Kaufman's, Ms. Perry's, and Mr. Jenks' recommended ROEs are too low, are not reflective of current market conditions, and are below the average allowed ROEs recently awarded to other vertically integrated utilities. Staff's DCF models (Model X, Model Y, and Constant Growth DCF) are downwardly biased because they delay dividend payments to equity holders, which is inconsistent with the frequency by which all of Staff's proxy companies pay dividends. Staff's DCF models are further downwardly biased because they rely on dividend growth rates, which ignore other ways that companies can distribute earnings to investors.
- Staff's DCF models also incorporate several erroneous ROE estimates that are near or below the cost of debt, which downwardly biases its sample average ROE estimates. Dr. Kaufman's adaptation of my DCF is problematic because he arbitrarily uses lower growth rates in the single-stage DCF that are not reflective of market expectations or based on any analysis or evidence that utility growth rates are lower. Staff's CAPM is problematic because it relies on the current risk-free rate, rather than a forecasted risk-free rate. Staff also includes in its sample average ROE an erroneous ROE estimate for Exelon which Staff reports has a beta of 0.0. Staff's CAPM relies on an MRP that is derived using the geometric average, which downwardly biases the ROE estimates. Academic finance is clear that the arithmetic mean is the appropriate measure when

estimating the cost of equity. Dr. Kaufman's adaptation of my CAPM is problematic because he relies on non-standard betas that selectively exclude market data and adjust the betas to the industry average rather than the market. This approach is not common and contains several issues in its implementation. Dr. Kaufman relies on Kroll's current "normalized" MRP which is highly problematic and inconsistent with the well-established inverse relationship between interest rates and risk premiums. Dr. Kaufman does not rely on standard financial techniques to adjust for differences in financial leverage between the proxy companies and PGE, despite recognizing the importance of such adjustments. Staff recognizes the impact financial leverage has on the cost of equity, but only applies a modified version of the Hamada Adjustment to its Model X and Model Y. Mr. Jenks' recommended ROE is based on out-of-date cost of capital analyses that are not reflective of current capital market conditions.

B. Summary of Recommendations

Q. Please summarize the ROE and capital structures put forth in this proceeding.

A. Figure 1 below summarizes the Company's, Staff's,[9] and the Intervenors' recommended ROE and equity capitals structure for PGE.

[9] *Note*, Staff provided a recommended range of ROEs for PGE but did not recommend a point estimate. *See* Staff/400, Muldoon/7.

Figure 1: Recommended ROE and Reasonable Ranges

Party	Recommended ROE	Low Range	High Range	Recommended Equity %
PGE/Figueroa[10]	**9.65%**	**10.25%**	**11.25%**	**50.0%**
OPUC Staff[11]	n/a	8.96%	9.41%	50.0%
Kaufman (AWEC)[12]	9.25%	7.6%	9.3%	44.6%
Jenks (CUB)[13]	9.2%	9.2%	9.4%	n/a
Perry (Walmart)[14]	n/a	n/a	n/a	n/a

Q. What is your reaction to Staff's and the Parties' recommended ROE for PGE?

A. Staff's and the Parties' recommended ROEs are simply too low. The midpoint of Staff's recommended ROE range, 9.2%, Mr. Kaufman's recommended ROE of 9.25%, and Mr. Jenks' recommended ROE of 9.2% represent a 25 to 30 basis point ("bps") reduction in PGE's currently allowed return on equity (9.5%). This is despite various market indicators that the return required by investors has remained elevated since the Commission established PGE's allowed ROE in its last rate case. For example, yields on 10-year U.S. Government bond yields are currently 3.99%, which is 11 basis points higher than when I prepared my Direct Testimony and 89 bps lower since the OPUC's prior ROE adoption in October 2023.[15] Inflation also remains well above the Federal Reserve's target of 2.0%.[16]

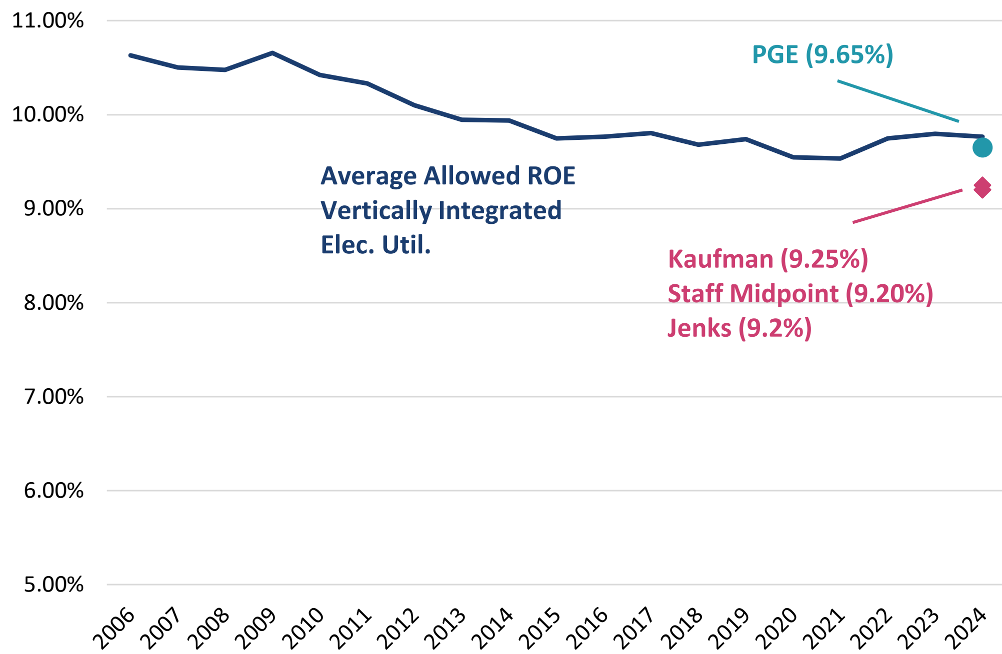
In addition, neither Staff nor the intervenors provide evidence that PGE's business risk profile warrants a lower allowed ROE. As I discussed in my Direct Testimony, PGE faces higher risks than the electric utility proxy companies due to, for example, its smaller size, its

[10] PGE/600, Figueroa – Liddle/17. *Note*, in the Figueroa-Liddle Testimony, the Company requested an allowed ROE of 9.75% but has since made a managerial decision to reduce the Company's requested allowed ROE to 9.65%.
[11] Staff/400, Muldoon/5, 7.
[12] AWEC/200, Kaufman/75.
[13] CUB/100, Jenks/70-71.
[14] *Note*, Ms. Perry does not offer a specific ROE or capital structure recommendation. *See* Walmart/100, Perry/13-14.
[15] PGE/600, Figueroa - Liddle/28 and FRED, "Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity," DGS10, as of October 30, 2023 and August 8, 2024, accessed August 12, 2024.
[16] U.S. Bureau of Labor Statistics, Consumer Price Index, Consumer Price Index News Release, USDL-24-1325, July 11, 2024, https://www.bls.gov/news.release/archives/cpi_07112024.htm.

asymmetric power cost adjustment mechanism, and wildfire risks.[17] All else equal, these business risk factors indicate that a lower allowed ROE is inappropriate.

Further, recently allowed ROEs for electric utilities indicate that Staff's and the Parties' recommended ROEs are too low and would not provide a comparable, risk-adjusted return to investors. As shown in Figure 2 below, the average allowed ROE for vertically integrated electric utilities has steadily increased since 2021 and the 2024 year-to-date average is 9.77%, which is consistent with PGE's requested ROE of 9.65%.[18] Figure 2 also shows that Staff's and the Parties' recommended ROE are about 50 basis points below the current average allowed ROE.

Figure 2: Allowed ROE for Electric Utilities versus Staff's And Parties' ROE Recommendations[19]



Finally, as discussed in further detail in the following section, Staff's and the Parties' ROE estimation methodology suffers from several shortcomings that downwardly bias their

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[17] PGE/600, Figueroa – Liddle/51.
[18] S&P CapitalIQ Pro, Past Rate Cases, accessed July 22, 2024.
[19] PGE Exhibit 1800C-02.

cost of equity estimates for PGE. Making several reasonable adjustments to their methodologies increases their ROE estimates by about 60 to 215 basis points and their ranges become supportive of PGE's requested 9.65% ROE.

Taken together, this indicates that Staff's and the Parties' recommended ROEs are too low and are the result of several shortcomings in their ROE analyses. Staff even appears to recognize that their ROE results are, in fact, too low by discussing potential credit implications if the Commission were to adopt the lower end of its ROE range, which could go against the principle of the Fair Return Standard stating that the allowed ROE should allow a utility to maintain its credit.[20] Simply put, Staff's and the Parties' recommendations are too low and should not be given any weight by the Commission.

C. Rebuttal to Staff's and Intervenor's Approach to Estimating the Cost of Equity

Q. What do you cover in this section?

A. In this section, I address several shortcomings of Staff's and the Parties' cost of equity estimation methodologies and show that these approaches downwardly bias their ROE estimates. I also respond to some of the critiques they level against my implementation of the Capital Asset Pricing Model (CAPM), Discounted Cash Flow (DCF) model, and Risk Premium model.

<u>Overall Approach</u>

Q. Please provide a general overview of Staff's cost of equity estimation methodology.

A. Staff begins their cost of equity analysis by selecting a proxy group of regulated utilities with comparable risk to PGE. Specifically, Staff started with the companies that were classified as electric utilities by *Value Line*, which resulted in an initial sample of 37 proxy companies.[21]

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[20] Staff/400, Muldoon/8, 24-25.
[21] Staff/400, Muldoon/9-10.

Staff then applied seven additional screening criteria to determine its final proxy sample. Specifically, it excluded companies that did not meet the following criteria:

1. Has a *Value Line* beta of 1 or less;
2. Forecasted by *Value Line* to have positive dividend growth;
3. Long-term Issuer Credit Rating between Baa2 and A1, inclusive, from Moody's and from BBB- to A, inclusive, from S&P;
4. No decline in annual dividends in the last five years, according to *Value Line*;
5. Has heavily regulated electric utility revenue;
6. Has a debt capital structure of 45% to 55%, inclusive, comprised of long-term debt, according to *Value Line*;[22] and
7. Has no recent merger and acquisition activity.[23]

Applying the screening criteria resulted in 14 electric utilities in Staff's proxy sample.[24]

After selecting the proxy sample, Staff employs two versions of a three-stage DCF model to estimate the cost of equity.[25] The first is a three-stage dividend discount model that incorporates a terminal valuation based on perpetual growth (Model X).[26] The second model is a three-stage dividend discount model that incorporates a terminal valuation based on Staff's escalated price-to-earnings (P/E) ratio (Model Y).[27]

Both models assume an initial growth phase based on three to five-year dividend growth rates, as reported by *Value Line*.[28] Then a five-year transition phase occurs where the first

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[22] Staff also performed a sensitivity to include companies with a debt capital structure of 40% to 60%, inclusive, but Staff found this relaxed screening criteria had no impact on its modeling results. *See* Staff/100, Muldoon/9, footnote 7.
[23] Staff/400, Muldoon/9.
[24] *Id.*, 10.
[25] *Id.*, 15.
[26] *Ibid*.
[27] *Id.*, 15-16.
[28] Staff Exhibit 402.

stage growth rates gradually converge with the long-term growth rate used in the final stage. Staff relied on three different sources to derive the long-term growth rate.[29] The first is the U.S. Social Security Administration's nominal 20-year GDP growth rate forecast (4.39%).[30] The second is the U.S. Congressional Budget Office's 20-year GDP growth rate estimate (4.46%).[31] The third is a composite growth rate with 20% weight given to long-term real growth rates from the U.S. Energy Information Agency, Organization for Economic Co-operation and Development, the U.S. Social Security Administration, the Congressional Budget Office, and the U.S.' historic real GDP growth rate.[32] Each of the composite growth rate components are converted to a nominal basis using U.S. Treasury Inflation Protected Securities ("TIPS").[33] The final composite growth rate is 4.58%.[34]

Both of Staff's DCF models assume that each of the proxy companies pays dividends on an annual basis.[35] However, Staff performs two sets of calculations assuming the annual dividends are paid either at the beginning or end of the period.[36] To calculate the stock price in both models, Staff relies on the average closing price of each utility's closing stock price on the first trading day of December 2023, January 2024, and February 2024.[37]

Staff's Model X resulted in ROE estimates that ranged from 8.96% to 9.12% based on Staff's Peer Screen and Model Y resulted in ROE estimates that ranged from 9.27% to 9.41%

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[29] Staff/400, Muldoon/16.
[30] *Id.*, 18.
[31] *Ibid*.
[32] *Id.*, 18-19.
[33] *Id.*, 19.
[34] *Ibid*.
[35] *Id.*, 17.
[36] *Ibid*.
[37] *Ibid*.

also using Staff's Peer Screen. After applying a Hamada Adjustment, Staff finds a reasonable range of ROE estimates of 8.96% to 9.41%.[38]

As a check to its ROE estimates, Staff also calculates the cost of equity using two additional models. The first is a Gordon Growth Model (single stage DCF), which results in an ROE estimate of 8.7% based on Staff's Screen.[39] The second model is the CAPM, which results in an ROE estimate of 8.7% based on Staff's Screen.[40]

Q. Does Staff recognize the impact that financial leverage can have on the cost of equity?

A. Yes. Staff recognizes the importance of accounting for differences in financial leverage between the proxy companies and PGE. As Staff explains in their testimony:

> Different amounts of debt financing along with different tax rates result in disparate risk profiles among peer utilities used in ROE modeling to approximate the unknown appropriate ROE for the utility examined. **All else equal, with more debt in a capital structure, investors require higher expected equity returns to compensate for the increased risk.**[41]

Staff employs the Hamada Adjustment, which is typically used in the CAPM to unlever a proxy company's beta and then re-lever it to a company's requested capital structure. In its version of Hamada, Staff unlevered the proxy companies' *Value Line* betas using their book capital structure. The unlevered (or asset) beta is then re-levered to PGE's requested 50.0% equity capital structure. Staff then calculated a "Hamada Adjustment" as the difference between the re-levered beta and the original *Value Line* beta multiplied by an equity risk premium of 4.5%.[42] Staff's average Hamada Adjustment is -0.12% for the sample, which it adds to it DCF-based ROE estimates.[43]

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[38] Staff Exhibit 404.
[39] Staff Exhibit 406.
[40] Staff Exhibit 405.
[41] Staff/400, Muldoon/23. Emphasis added.
[42] Staff Exhibit 402.
[43] *Ibid*.

Q. Please provide a general overview of Dr. Kaufman's cost of equity estimation methodology.

A. Dr. Kaufman adopts my proxy sample and CAPM and DCF models, except he makes four changes to inputs to derive his recommended ROE of 9.25%.[44] Namely,

- He does not apply standard financial adjustments to account for differences in financial leverage because he argues that PGE and the proxy group have similar capital structures;[45]
- In the constant growth (single stage) DCF, he relies on growth rates that he says reflect short and long-term expectations;[46]
- He relies on his own beta estimates, which he adjusted to a.) remove certain data from the time of the COVID-19 pandemic and b.) adjusts the betas to the industry average, rather than the market average;[47] and
- He replaces the historic market equity risk premium with Kroll's published estimate of the MRP;[48]

Dr. Kaufman's implementation of the DCF results in an ROE estimate of 8.9% (multi-stage) to 9.3% (single-stage) and his CAPM ROE results range from 7.6% (CAPM, 5% MRP) to 9.0% (ECAPM, 6.37% MRP).[49]

He does not adopt my Risk Premium Model, arguing that it is circular and not consistent with market data and financial theory.[50]

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[44] AWEC/200, Kaufman/40-42, 45.
[45] *Id.*, 45.
[46] *Ibid*.
[47] *Id.*, 45-46.
[48] *Id.*, 46.
[49] *Id.*, 75.
[50] *Ibid*.

Q. What is the basis for Mr. Jenks' 9.2% ROE recommendation for PGE.

A. Mr. Jenks does not provide his own estimation of PGE's cost of equity estimation methodology. Instead, he re-submits the Direct and Rebuttal Testimony sponsored by Christopher C. Walters in PGE's prior rate case proceeding (UE-490).[51] Mr. Jenks recommends an allowed ROE for PGE of 9.2% based on the lower end of the recommended range in Mr. Walters' Testimony. Notably, the cost of equity analysis performed by Mr. Walters is over a year old and not reflective of current capital market conditions or investors' expectations.[52] Further, any issues with Mr. Walters' testimony and cost of capital analyses were addressed in Docket No. UE-490. Ultimately, I find Mr. Jenks' ROE recommendation of 9.2% to be too low and premised on out-of-date cost of equity analyses—his recommendation should simply be ignored.

<u>Proxy Sample</u>

Q. What concerns do you have with Staff's proxy sample selection criteria?

A. While Staff's and my proxy groups include many of the same companies, I find that several of Staff's sample selection criteria are arbitrary and they result in the exclusion of numerous proxy companies relevant to estimating the cost of equity for PGE.

Staff excludes proxy companies with *Value Line* betas greater than 1.0 because "typically utilities are less volatile than other stocks in general."[53] While utility betas have typically been below 1.0 in the past, Staff offers no evidence or analysis to support that utility betas cannot be greater than 1.0 and, in such instances, makes them poor comparators to estimate the cost of equity for PGE. This is arbitrary and not supported. I do not endorse this criterion, but it

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[51] CUB/100, Jenks/69-70.
[52] CUB Exhibit 118, p. 31.
[53] Staff/400, Muldoon/9.

worth noting that it is not consistently applied either because OGE with a beta of 1.05 is included in the proxy sample.[54]

Similarly, Staff excludes proxy companies that do not have a book debt capital structure between 45% and 55%, inclusive. These thresholds are also arbitrary and Staff offers no support to justify them. Staff offers no evidence or analysis to support why a utility with a capital structure outside of these parameters is not comparable to PGE. Further, to the extent that Staff is screening for financial risk, it is the proxy company's market value capital structure (not book value capital structure) that determines the amount of financial risk. In addition, as Staff acknowledges, differences in capital structures can be accounted for using well-established financial techniques, such as the Hamada Adjustment (which Staff employs in its cost of equity analysis), therefore this screening criterion is not necessary.[55] This arbitrary criterion excludes CMS, Otter Tail, Southern, and Xcel, which passed all of Staff's other criteria.[56]

Staff's credit screening criteria also suffers from arbitrary thresholds that are not supported and not consistently applied. Specifically, Staff excludes companies that do not have long-term issuer credit ratings from Moody's from A1 to Baa2, inclusive, and from S&P from A to BBB-, inclusive. Staff is relying on different thresholds resulting in an inconsistent application of this criterion. Figure 3 below is a replication of Staff's credit rating matrix.[57] As shown with the blue boxes, Staff relies on a BBB- lower threshold using the S&P scale, which is the lowest rating before a non-investment grade rating. Staff inexplicably then relies

[54] Staff Exhibit 402.
[55] Staff/400, Muldoon/22-23.
[56] Staff Exhibit 402. Other proxy companies, such as AEP, DTE, Duke, Edison International, Entergy, Exelon, and NextEra were also excluded due other Staff criteria.
[57] *Ibid*.

on a lower threshold of Baa2 on the Moody's scale, which is *one rating above* Moody's lower rating before a non-investment grade credit rating (Baa3). Staff's upper thresholds (green boxes) are similarly shifted (A vs. A1). This arbitrary shift causes Fortis (A-, Baa3) and MGE (AA-, A1) to fail this criterion.[58] MGE, with the highest credit rating in of Staff's potential proxy companies, highlights another issue with Staff's credit rating criterion: Staff offers no explanation as to why a proxy company should be excluded because it has too high of a credit rating or why a higher credit rating makes it a poor comparator. Instead, Staff should simply screen for utility proxy companies that have an investment grade credit rating.

Figure 3: Replication of Staff's Credit Rating Matrix[59]

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		High grade
Aa2		AA		AA		AA	R-1M	
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)	R-1L	Upper medium grade
A2		A		A		A		
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	Lower medium grade
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1	Not prime	BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		Highly speculative
B2		B		B		B	R-5	
B3		B-		B-		B(low)		
Caa1		CCC+	C		C	CCC(high)		Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
						CC(high)		
		CC		CCC		CC		

[58] *Ibid*. Note, Staff incorrectly asserts that MGE is not covered by *Value Line.* As of the end of February when Staff apparently ran its model, MGE is covered by *Value Line* and has a beta of 0.8.

[59] Green and blue boxes in Moody's and S&P columns added.

Staff also excluded companies for having insufficient regulated electric utility revenues. First, neither Staff's testimony nor its workpapers specify the revenue threshold used for this criterion.[60] Second, I find it more appropriate to screen proxy companies for the amount of assets that they have dedicated to regulated activities. Fundamentally, it is a company's regulated assets that are used to derive a utility's revenues – that is, revenues are a secondary measure of a company's regulated activities. Staff's workpapers show DTE and Exelon would pass this screen if Staff relied upon regulated assets.

Finally, Staff excludes proxy companies if they had a decline in dividends in the past five years or recent material M&A activity. While I apply similar screening criteria,[61] I find Staff's criteria are too broad to appropriately consider if such activity affects the proxy companies, stock price, growth rates, *etc.*, which would then impact the cost of equity estimates. For example, I look five years back for pending M&A transactions and six months back for completed or terminated transactions because such events typically affect a company's stock price in ways that are not representative of how investors perceive business and financial risk characteristics.[62] I look for dividend cuts that occurred in the six months prior to the date of my analysis for similar reasons.[63] Whereas, Staff broadly looks to the past five years for both of these criteria.

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[60] Staff Testimony, p. 9 and Staff Exhibit 402.
[61] PGE/600, Figueroa – Liddle/35.
[62] *Ibid*.
[63] *Ibid*. *Note*, Staff erroneously excludes MGE for having a dividend cut in the past five years, but MGE has not cut its dividend in that time frame. *See*, MGE Energy, Dividends, https://www.mgeenergy.com/invest/dividends.

<u>Discounted Cash Flow Model</u>

DCF Inputs and Implementations

Q. What are the main considerations when implementing the DCF model?

A. There are three key factors to consider when implementing the DCF model. First, the inputs to the DCF model are the proxy companies' dividend (or cash) yield (*e.g.*, expected divided by current stock price); proxy company growth rates; and the long-term (or sustainable) growth rate for multi-stage DCF models. Second, it is important to capture the appropriate timing of modeled distributions to shareholders—utilities commonly pay dividends quarterly, so it is preferable to use a quarterly DCF model. Third, in addition to dividends, companies distribute earnings in other ways, such as share buybacks—it is important to capture all *cash flows* to investors, not just dividends.

Q. Based on these main considerations, what are your concerns with Staff's implementation of its DCF models?

A. I have concerns with Staff's DCF model with regards to all three of the key components discussed above. First, Staff relies on the average closing stock price of the proxy companies on the first trading day of December 2023, January 2024, and February 2024.[64] While I agree with Staff that using an average stock price is preferable to using a single-day stock price because it limits the impact of any one day stock price movement, Staff's averaging methodology is arbitrary and its multi-month duration is not reflective of current stock prices, as required by the DCF model. If Staff had used a 14-day average stock price as of the end of February 2024, its Model X and Model Y ROE estimates would increase by about 10 bps.[65]

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[64] Staff/400, Muldoon/17.
[65] I find that using a 14-day average stock price balances the need to use a current stock price while limiting the impact of a single day stock price movement.

Second, Staff's DCF relies on annual dividend payments.[66] As stated above, utilities typically pay dividends to investors on a quarterly basis. In fact, all of the companies in Staff's proxy companies pay quarterly dividends, not annual dividends.[67] By ignoring the timing of when the proxy companies pay dividends, Staff's annual dividend approach extends the time it takes for an equity investor to receive its dividend. As the notion of the time value of money states, a dollar today is worth more than a dollar later. Delaying the dividend payments in the DCF model downwardly biases Staff's ROE estimates by about 6 to 12 basis points. Quarterly dividend and growth rate data is readily available or can be calculated using data provided by *Value Line*.

Finally, Staff's DCF models are calculated based on dividend payments from the proxy companies to investors. It is ultimately a company's earnings that is a more fundamental measure of cash flows available to equity holders. Companies can decide to retain and reinvest those earnings in the company, pay dividends, repurchase shares, *etc.*, which create various forms of returns for equity investors. That is, earnings dictate a company's ability to pay a dividend and sustain dividend growth over the long term and is thus a more appropriate measure when using the DCF Model to estimate the cost of equity.[68] Staff calculates its dividend growth rate based on each proxy company's average dividend from 2020 to 2022 and the average of *Value Line*'s forecasted growth rates from 2026 to 2028.[69] This results in an average dividend growth rate of 4.2% for the proxy sample.[70] Staff also performs a similar calculation with earnings per share ("EPS") growth estimates from *Value Line*, which are

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[66] Staff/400, Muldoon/17.
[67] Proxy companies' investor relations websites and Nasdaq.com.
[68] The DCF is the discounted *cash flow* model and should account for all the various ways that companies distribute cash flows to equity holders
[69] Staff Exhibit 402.
[70] *Ibid*.

more inclusive of cash flows available to equity holders. The average EPS growth rate for the proxy sample is 5.1%, which is notably 90 basis points above the dividend growth rate. However, Staff only relies on the EPS growth rate to calculate the stock sale price in Model Y. Using a lower growth rate that only reflects dividends and not other forms of cash flow available to equity holders downwardly biases Staff's ROE estimates by 96 to 109 basis points.

Q. Does Staff include illogical ROE estimates in their calculation of the sample average ROEs?

A. Yes. A fundamental tenant of finance is that the cost of equity is higher than the cost of debt due to debtholders higher claim on the company's earnings.[71] However, on three occasions, Staff incorporates ROE estimates that are near or below the cost of debt when calculating its Company Screen and Staff Screen averages. Using Staff's recommended cost of long-term debt of 4.641%,[72] I observe the following instances of illogically low DCF-derived ROE estimates:

- In the single stage DCF, Staff calculates an ROE of 1.4% for PPL, which is 3.24% *below* the cost of debt;[73]
- In the single stage DCF, Staff calculates an ROE of 0.8% for Sempra, which is 3.84% *below* the cost of debt;[74] and

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[71] Brealey, Myers and Allen, "Principles of Corporate Finance," 12th Edition (2017), p. 224.
[72] Staff/400, Muldoon/4.
[73] Staff Exhibit 406.
[74] *Ibid*.

- In Model Y, Staff calculates an ROE of 4.79% (EOY Cash Flows) and 4.94% (BOY Cash Flows) for Otter Tail, which is only about 14 to 29 bps above the cost of debt.[75]

Removing PPL and Sempra from the single stage DCF increases the average ROE for the Company Screen from 8.4% to 9.1%; the Staff Screen from 8.7% to 9.3%; and the Staff Sensitivity Screen from 8.8% to 9.2%. Similarly, removing Otter Tail from Model Y increase the average ROE for the Company Screen from 9.03% to 9.20% and the Staff Sensitivity Screen from 9.08% to 9.31%. Staff's inclusion of these errant ROE estimates downwardly biases its calculated averages, which Staff relies on when determining the appropriate placement of PGE's allowed ROE within the range of its results.[76]

Q. What concerns do you have with Dr. Kaufman's implementation of the DCF models?

A. Dr. Kaufman largely adopts my implementation of the DCF models except he replaces the 3-5 year analyst growth rates in the single-stage DCF models with his own growth rate, which he alleges "appropriately balances short-term and long-term expectations."[77] Specifically, he averages the short-term analyst growth rates, the tapered growth rates during the five years of the second stage, and the long-term nominal GDP estimate.[78] I disagree with the use of Dr. Kaufman's growth rate. It is highly arbitrary—he offers no support or analysis to indicate that the proxy companies' growth rates should be lower (or higher). In contrast, I rely on consensus growth rate estimates from equity analysts that follow and analyze the proxy companies, sourced from *Value Line* and *IBES*.[79] These are standard sources of growth rate

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[75] Staff Exhibit 403.

[76] "The Gordon Growth Model generated a mean of 8.7 percent using Staff's peer electric utilities and 8.4 percent with the Company's peer electric utilities…This model points to the lower end of Staff's three-stage discounted cash flow results." Staff Testimony, p. 8.

[77] AWEC/200, Kaufman/49. For clarity, he makes no apparent changes to the growth rate used in the multi-stage DCF.

[78] Exhibit AWEC 204.

[79] PGE/600, Figueroa – Liddle/42-43.

estimates that are relied upon in regulatory settings, including in Oregon, and by investors.[80] Further, the multi-stage DCF model addresses Dr. Kaufman's concern by relying on different growth rates in each stage of the model. In my implementation of the multi-stage DCF, I taper the analyst growth rates up or down to the long-term nominal GDP growth rate[81] (which Dr. Kaufman fully adopts in his testimony).[82] His growth rate adjustments to the single-stage DCF are arbitrary, not supported, and downwardly bias his ROE recommendation – it should not be given any weight.

Finally, Mr. Kaufman does not rely on standard financial adjustments to account for differences in financial leverage between the proxy groups and PGE, despite recognizing the impact financial leverage can have on the cost of equity.[83] Both Staff and I make such adjustments in our ROE estimation methodologies. I address financial leverage adjustments more fully below. Failure to make such adjustments does not provide a fair, risk-adjusted return for PGE.

Q. What critiques does Dr. Kaufman raise about the growth rates used in your DCF Model?

A. Dr. Kaufman takes issue with the use of 3-5 year analyst growth rate estimates in the single stage (constant growth) DCF because it does not reflect the proxy companies' long-term dividend growth rates.[84] He also calls into question why I rely on 3-5 year analyst growth rate estimates only in the first stage of my multi-stage DCF, rather than in all three stages, if I truly believe that short term growth rates would persist indefinitely.[85]

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[80] *See* Staff/400, Muldoon/15.
[81] PGE/600/Figueroa – Liddle/43.
[82] AWEC/200, Kaufman/ 49 and Exhibit AWEC 204.
[83] *See* AWEC/200, Kaufman/47.
[84] *Id.*, pp. 48-49.
[85] *Ibid*.

Q. How do you respond to Dr. Kaufman's concern about your implementation?

A. I disagree with Mr. Kaufman and continue to find both the single-stage and multi-stage DCF models, as implemented, informative for estimating PGE's cost of equity. I acknowledge that there are advantages and disadvantages to the single-stage DCF, just like any other cost of equity model. This "model risk" is why it is important to rely on multiple complementary models when estimating the cost of equity. That said, the single-stage DCF model should not be disregarded because it relies on a single analyst growth rate in perpetuity. Utilities can grow faster than the economy for an extended period of time,[86] particularly as the energy landscape is evolving. For example, electric utilities, like PGE, may experience an extended period of high growth from system reinforcement work to accommodate the interconnection of renewable generation and increasing loads from new customers (*e.g.*, building electrification, electric vehicles, data centers, *etc.*). For the same reason, the multi-stage DCF model that limits analyst growth rates to the first five years of the model may understate the cost of capital. Taken together, I find it important to consider both the single-stage and multi-stage DCF models, along with each model's advantages and disadvantages, when determining a recommended ROE.

In addition, I also disagree with Dr. Kaufman's suggestion to use the proxy company's long-term dividend growth rate. As discussed above, doing so leaves out other ways that companies can and do return earnings to investors (*e.g.*, share buybacks). Failure to account for these other forms of equity returns will understate the DCF-based cost of equity estimates. For this reason, I rely on earnings per share growth rate forecasts.

[86] *Note*, my implementation of the multi-stage DCF model tapers short-term analyst growth rate forecasts up or down in the second stage to converge with the long-term nominal GDP growth rate used in the third stage.

Impacts on the DCF-Based ROE Estimates

Q. Could you please illustrate the impact of your various concerns regarding Staff's DCF models on their ROE estimates?

A. Yes. In Figure 4 below, I make three standard adjustments to Staff's Model X, Model Y, and Constant Growth DCF models. First, I updated the stock prices to reflect the 15-day average ending February 29, 2024. Second, I adjust Staff's DCF models to be on a quarterly dividend basis. Third, I use Staff's EPS growth rate estimates in place of the dividend growth rate estimates to account for additional forms of cash flows to investors. In addition, I adjust Staff's proxy sample to correct for Staff's improper exclusion of certain proxy companies:

- AEP: Improperly excluded due to book capital structure and M&A transactions that completed more than six months ago[87] and are not of material size;[88,89]
- CMS: Improperly excluded due to book capital structure;
- Duke: Improperly excluded due to book capital structure and M&A transactions that closed more than six months ago;[90]
- Edison International: Improperly excluded due to book capital structure and M&A transactions that closed more than six months ago;[91]

[87] Algonquin Power & Utilities Corp., "Algonquin Power & Utilities Corp. and American Electric Power Mutually Agree to Terminate Kentucky Power Transaction," April 17, 2023, https://www.prnewswire.com/news-releases/algonquin-power--utilities-corp-and-american-electric-power-mutually-agree-to-terminate-kentucky-power-transaction-301798512.html.

[88] American Electric Power, "AEP Signs Agreement to Sell Distributed Resources Business to Basalt," May 13, 2024, https://www.aep.com/news/releases/read/9540/AEP-Signs-Agreement-to-Sell-Distributed-Resources-Business-to-Basalt. *Note*, this transaction occurred after Staff's analysis date.

[89] *Note*, I exclude companies that recently closed or are pending M&A transactions with a cumulative announced deal value equal to 30% of the companies market capitalization or greater.

[90] Duke Energy, "Duke Energy and GIC close first phase of minority investment in Duke Energy Indiana," September 8, 2021, https://news.duke-energy.com/releases/duke-energy-and-gic-close-first-phase-of-minority-investment-in-duke-energy-indiana.

[91] Edison International, "Our History," https://www.edison.com/about-us/our-history.

- Entergy: Improperly excluded due to book capital structure and M&A transactions not of material size;[92]
- PPL: Improperly excluded due to book capital structure and M&A transactions that closed more than six months ago;[93]
- Southern: Improperly excluded due to book capital structure; and
- Xcel: Improperly excluded due to book capital structure.

Together, these changes result in about a 40 to 160 basis point increase in Staff's cost of equity estimates.[94] These corrected estimates are supportive of PGE's requested 9.65% ROE.

Figure 4: Corrected Staff DCF Results[95]

	Staff	Corrected	Difference
Model X	8.9%	9.5%	0.6%
Model Y	9.2%	9.7%	0.4%
Constant Growth	8.7%	10.2%	1.6%

Q. What is the impact of your concerns on Dr. Kaufman's DCF methodology and the resulting ROE estimates?

A. As discussed above, I disagree with Dr. Kaufman's growth rate adjustments to my single-stage DCF model. I also disagree with his decision to disregard the standard financial techniques to adjust for differences in financial leverage between the proxy companies and PGE. Given that Dr. Kaufman adopts my DCF Models and then makes these adjustments, I find that these

[92] Entergy, "Entergy announces agreement to sell gas distribution business to Bernhard Capital Partners," October 30, 2023, https://www.entergynewsroom.com/news/agreement-to-sell-gas-distribution-business-to-bernhard-capital-partners/. *Note*, Staff incorrectly lists the size of the transaction as $1.2 billion, rather than $484 million.

[93] PPL Corporation, "PPL Corporation completes acquisition of Rhode Island's primary electric and natural gas utility," May 25, 2022, https://www.prnewswire.com/news-releases/ppl-corporation-completes-acquisition-of-rhode-islands-primary-electric-and-natural-gas-utility-301555014.html.

[94] *Note,* recognizing the fundamental financial principle that the cost of equity is higher than the cost of debt, I exclude ROE estimates that are less than 1.5% above Staff's risk-free rate, consistent with the approach I relied upon in my ROE estimation methodology.

[95] PGE Workpaper_ROE Corrections_CONF.

adjustments downwardly bias his DCF estimates by 60 to 195 basis points relative to my reasonable range of DCF estimates.

Capital Asset Pricing Model

Preliminaries

Q. How does Staff use the CAPM in its estimation of PGE's ROE?

A. Staff only relies on the CAPM to validate its DCF-derived cost of equity estimates because Staff contends that the CAPM has historically been unreliable.[96] Staff argues that this is because the CAPM only relies on a few inputs (*i.e.*, risk-free rate, beta, and the market equity risk premium) and two of those inputs—beta and the market equity risk premium—could be used by an "uninformed or malicious" analyst to motivate abnormal required returns.[97]

Q. How do you respond to Staff's argument that the CAPM is unreliable?

A. The CAPM is a widely used and accepted financial model and should not simply be disregarded because of uncertainty related to its inputs. The CAPM was developed by William Sharpe, John Lintner, and Jack Treynor, for which William Sharp ultimately won a Nobel Prize in 1990. The CAPM is widely taught in standard MBA textbooks[98] and the CFA curriculum[99] and relied on by financial data subscription providers.[100] Numerous regulatory agencies also rely on CAPM, alongside other models, to determine the allowed ROE.

[96] Staff/400, Muldoon/31-33.
[97] *Ibid*.
[98] *See*, Brealey, Myers and Allen, "Principles of Corporate Finance," 12th Edition (2017), p. 200; Berk & DeMarzo, "Corporate Finance," 3rd Edition (2013), pp. 379-381; Ross, Westerfield, Jaffe, "Corporate Finance," 6th Edison (2003), p. 248.
[99] CFA Institute, "Portfolio Risk and Return: Part II," accessed July 25, 2024, https://www.cfainstitute.org/en/membership/professional-development/refresher-readings/portfolio-risk-return-part-2.
[100] *For example*, Kroll (Cost of Capital Navigator) and Bloomberg (Weighted Average Cost of Capital, p. 14).

For example, FERC,[101] the Surface Transportation Board,[102] Washington Utilities and Transportation Commission,[103] New York Public Service Commission Staff,[104] the Illinois Commerce Commission,[105] the Michigan Public Service Commission,[106] the California Public Utilities Commission,[107] Hawaii Department of Commerce and Consumers Affairs,[108] the Massachusetts Department of Public Utilities,[109] and others all rely on the CAPM. While there are limitations with any model, this illustrates that numerous financial analysts regularly rely on multiple models, including the CAPM, to set the authorized ROE for utilities.

Staff's contention with the CAPM is that there are numerous sources and ways to measure the beta and market equity risk premium, which make them vulnerable to "unrepresentative values to motivate abnormal required returns."[110] However, there is nothing unique about the CAPM in this respect. All standard financial models, such as the DCF, require some amount of discretion by the analysts to determine the appropriate inputs to estimate the cost of equity. The DCF relies on three inputs (dividends, growth rates, and stock price)[111] similar to how the CAPM relies on three inputs. I agree with Staff that an analyst must be thoughtful and consistent when choosing CAPM (or DCF) inputs. Those inputs must reasonably represent the market conditions that are expected to prevail during the period when the company is

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[101] Federal Energy Regulatory Commission, Order 569-A, Docket No. EL14-12-004 and EL15-45-013, 171 FERC ¶61, 154, May 21, 2020
[102] Surface Transportation Board Decision, "STB Ex Parte No. 664 (Sub-No. 1)," Decided January 23, 2009 and most recently re-affirmed in "STB Ex Parte No. 664 (Sub-No. 4)," issued June 23, 2020.
[103] Washington Utilities and Transportation Commission, Order 12, Docket UE-152253, September 1, 2016.
[104] New York State Department of Public Service, Prepared Testimony of Staff Finance Panel, Cases 21-G-0073 and 21-E-0074, May 2021.
[105] Illinois Commerce Commission, Direct Testimony of Rochelle Phipps, Docket No. 21-0098, May 11, 2021.
[106] Michigan Public Service Commission, Direct Testimony of Joseph Ufolla, Case No. U-20642, May 24, 2020.
[107] California Public Utilities Commission, Decision 18-03-035, March 22, 2018.
[108] Hawaii Public Service Commission, Decision and Order No. 24171, May 1, 2008, p. 76
[109] Massachusetts Department of Public Utilities, Order, Docket No. 23-80, June 28, 2024.
[110] Staff/400, Muldoon/31.
[111] While the stock price and dividend can be readily observed, analysts could use different methodologies to determine the stock price or use different dividend timing methodologies.

raising capital to finance its business. For example, an analyst can select a single set of inputs or a set of inputs that bound the range of reasonably expected market conditions. In addition, the analyst can rely on multiple models to estimate the cost of equity and weigh the relative strengths and weaknesses of each model when determining their recommended ROE.[112]

The Commission should not disregard the results from the CAPM because there is uncertainty with the inputs. Staff has not provided any evidence that CAPM is any more unique in this respect than, say, the DCF. Instead, the inputs should be scrutinized to determine whether they reasonably represent expected market conditions.

Q. Staff asserts that the Commission has determined that "the CAPM should not be relied upon as a stand-alone modeling method."[113] How do you respond?

A. Staff's assertion does not accurately reflect the Commission's determination in Order No. 01-777 and Order No. 01-787 cited by Staff.[114] In Order No. 01-777, the Commission acknowledged that it had relied on the CAPM "as an appropriate method for estimating a utility's cost of common equity for over 20 years."[115] However, the Commission raised concerns with Staff's CAPM analyses because it produced cost of equity estimates below PGE's then-current cost of debt,[116] which violates a basic tenet of financial theory. The Commission goes on to conclude:

> *While the results in this case cast further doubt on the validity of Staff's CAPM methodology, **we do not believe that CAPM should be rejected in its entirety**. We continue believe that, in certain cases, CAPM analyses may provide a useful and reliable addition to the DCF results for determining the cost of equity. After*

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[112] *Note*, in Order 569-A, FERC explicitly recognizes the importance of considering multiple models, including the DCF and CAPM. "We continue to find that ROE determinations should consider multiple models, both to capture the variety of models used by investors and to mitigate model risk" FERC Order 569-A, Docket No. EL14-12-004, May 21, 2020, p. 25.

[113] Staff/400, Muldoon/33-34.

[114] *Ibid*.

[115] UE 115, Order No. 01-777 at 32, (August 31, 2001).

[116] *Ibid*.

> *our review of the results in this case, however,* ***we further conclude that the CAPM does not provide supportable and reasonable results <u>in this docket</u>***.[117]

Similarly, in Order No. 01-787, the Commission found similar concerns with Staff's CAPM-derived ROE estimates because they were below PacifiCorp's then-current cost of debt.[118] The Commission was also not convinced that Staff's "upward adjustments and rounding of results" accurately and fully compensated for the deficiencies in Staff's CAPM.[119] The Commission reached a near-identical determination as the one in made in Order No. 01-787:

> *While the results in this case cast further doubt on the validity of Staff's CAPM methodology,* ***we do not believe that the CAPM should be rejected in its entirety****.* ***We continue to believe that, in certain cases, CAPM analyses may provide a useful and reliable addition to the DCF results for determining cost of equity****. After our review of the results in this case, however, we further conclude that the CAPM does not provide supportable and reasonable results* ***<u>in this docket</u>***.[120]

In neither order cited by Staff did the Commission state that CAPM should not be relied upon as a standalone model in all cases. The Commission's determination to reject the CAPM was explicitly limited to those two dockets and the shortcomings of Staff's CAPM methodologies therein. Further, the Commission explicitly stated that it finds the CAPM "useful and reliable" and complementary to the DCF when determining the cost of equity.

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[117] *Ibid*. (Emphasis added)
[118] UE 116, Order No. 01-787 at 30-31, (September 7, 2001).
[119] *Ibid*.
[120] *Ibid*. (Emphasis added)

CAPM Inputs and Implementation

Q. What inputs does Staff rely upon in its implementation of the CAPM.

A. Staff uses a risk-free rate based on 30-year U.S. Treasury bond yields as of February 24, 2024 (4.348%).[121] Staff also calculates an MRP using annualized S&P 500 return data over 30-years (9.08%) paired with current 30-year U.S. Treasury yields (4.348%), resulting in an MRP of 4.73%.[122] Staff's beta estimates are sourced from *Value Line* as of Q3 2023.[123] While Staff applies the Hamada Adjustment betas in the DCF Model, Staff does not apply the Hamada Adjustment to its CAPM results. That is, Staff's CAPM estimates do not account for differences in financial leverage between the proxy companies and PGE.

Q. What concerns do you have with Staff's risk-free rate?

A. Staff relies on current yields on long-term Treasury bonds as its risk-free rate, which is not reflective of the capital market conditions that will prevail when PGE's rates are in effect.

Since the time of my Direct Testimony, inflation has persisted and remains above the Federal Reserve's target of 2% on average. As of June 2024, the U.S. Bureau of Labor Statistics reports that the Consumer Price Index was 3.0%, which is above the Federal Reserve's target of 2.0% on average.[124] While this is lower than the high of 9.1% in 2022, it is a continuation of a trend since June 2023 where CPI has persisted at around 3.0%.[125] The Federal Reserve has maintained a restrictive monetary policy to combat inflation.[126]

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[121] Staff/400, Muldoon/31 and Staff Exhibit 406. *Note*, Staff states that they also rely on the 10-year U.S. Treasury bond to determine the risk-free rate. However, Staff Workpaper 406 labels the risk-free rate as "30-Yr UST Yield." Based on yields posted on the WSJ website cited by Staff, it appears that Staff is only 30-year U.S. Treasuries and not 10-year U.S. Treasuries in its CAPM.

[122] *Ibid*.

[123] Staff Exhibit 406.

[124] U.S. Bureau of Labor Statistics, Consumer Price Index News Release, USDL-24-1325, July 11, 2024, https://www.bls.gov/news.release/archives/cpi_07112024.htm.

[125] PGE/600, Figueroa – Liddle/25.

[126] Federal Reserve, "Transcript of Chair Powell's FOMC Press Conference," July 31, 2024, https://www.federalreserve.gov/mediacenter/files/fomcpresconf20240731.pdf.

While the Federal Reserve has recently signaled that rate cuts are possible, the exact timing and extent of which are not certain and will depend on how capital market conditions evolve.[127] The latest issue of *Blue Chip Financial Indicators* forecasts that the yield on 10-year U.S. government bonds will average 4.2% in 2024 and 3.9% in 2025.[128] Applying my estimate of the maturity yield between 30-year and 10-year bonds (50 basis points),[129] this implies a forecasted 30-year government bond yield of 4.7% and 4.4%, which is 5 to 35 bps higher than Staff's risk-free rate.

Q. What concerns do you have with Staff's beta estimates?

A. I generally agree with Staff's use of *Value Line* betas in its CAPM calculation. However, I am concerned that Staff arbitrarily excluded proxy companies with betas greater than 1.0 in its sample selection process. Staff provides no analysis or evidence to support why a utility's beta cannot be above 1.0 and, in such an instance, why it makes it a poor comparator. This arbitrary decision serves to downwardly bias the cost of equity estimates. I also have concerns that Staff does not adjust the proxy companies' betas to account for differences in financial leverage using the Hamada methodology. Staff does perform a financial leverage adjustment in its DCF implementation using the same *Value Line* betas. Failure to do so in the CAPM does not provide a fair risk-adjusted return for PGE.

I note there is also an error in Staff's calculation. Staff's reports a *Value Line* beta for 0.00 for Exelon but still erroneously includes Exelon in its CAPM calculation of the average Company Screen ROE.[130] *Value Line* does not report a beta for Exelon as of the end of

[127] *Id.*, 3.
[128] Wolters Kluwer Blue Chip Economic Indicators and PwC Analysis, August 2024, p. 3-4.
[129] PGE Exhibit 605C-02. Based on average yields from April 1991 to December 2023.
[130] Staff/400, Muldoon/13 and Staff Exhibit 405.

February (*i.e.*, its *Value Line* beta is not zero).[131] Instead of excluding Exelon, Staff includes it in the Company Screen average, which downwardly biases the ROE estimate. Had Exelon been excluded, the average ROE would be 8.73% rather than 8.56%.

Q. What concerns do you have with Staff's market equity risk premium?

A. Staff's 30-year, geometric return-based market equity risk premium of 4.73% suffers from several flaws that downwardly bias the cost of equity estimates. Staff's choice of a 30-year historic period (1993 to 2023) is arbitrary. Staff provides no justification as to why this analysis horizon is appropriate, rather than long-term historic estimates like the *Ibbotson* and *Morningstar* estimates that Staff cites to support its MRP. It is more appropriate to use a long analysis horizon of 1926 to present, which corresponds to when high quality market data is available from the University of Chicago's Center for Research in Security Prices. Shorter-term estimates are overly influenced by recent market turmoil (dot-com bubble, 2007 financial crisis, 2020 COVID-19 pandemic) relative to a long-term estimate that balances out various periods of market growth and decline. This is supported by Professors Ross, Westerfield, and Jaffe who say in their textbook *Corporate Finance* that it is preferrable to use the longest period possible when measuring the MRP.[132] Staff appears to acknowledge the appropriateness of long-term historic MRP estimates because it cites to *Ibbotson*'s and *Morningstar*'s 1926 to present MRP estimates to justify its 4.73% MRP.

Second, Staff's reliance on geometric averages to calculate historic returns downwardly biases the MRP. Geometric returns are appropriately used to evaluate the historic *performance of a stock portfolio* (*i.e.*, the average annual achieved return over some time period). However, when *estimating the cost of capital*, which is a forward-looking concept, the goal is

[131] *Value Line*, as of February 29, 2024.
[132] Ross, Westerfield, Jaffe, *Corporate Finance,* 10th Edition (2013), pp. 324-327.

to estimate the rate of return that investors expect. For example, Dr. Morin in his textbook *Modern Regulatory Finance* states:

> In capital markets, where returns are a probability distribution, the answer that takes account of uncertainty, the arithmetic mean, is the correct one for estimating discount rates and the cost of capital. While the **geometric mean** is appropriate when measuring performance over a long time period, it **is incorrect when estimating a risk premium to compute the cost of capital**.[133]

Standard MBA textbooks also agree that the arithmetic mean is the appropriate metric when estimating the cost of capital. Brealey, Myers, and Allen's *Corporate Finance* textbook says:

> If the cost of capital is estimated from historic returns or risk premiums, use arithmetic averages, not compound annual rates of return[134] (i.e., geometric averages)

Staff's reliance on a historic MRP estimated using the geometric mean will downwardly bias the MRP, which can be shown statistically.[135] While I do not endorse Staff's 30-year MRP analysis period, *Kroll* reports that the historic MRP measured from 1993 to 2023 is 5.66% using the geometric mean, whereas it is 7.47% measured using the arithmetic average.[136] Staff's estimate of the MRP is inconsistent with its stated purpose (*i.e.*, to measure the cost of capital) and downwardly biases Staff's CAPM estimates by about 161 bps.[137]

My third concern with Staff's MRP is that they subtract the current risk-free rate from the 30-year market returns to derive a historic MRP estimate. The current risk-free rate reflects

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133 Roger A. Morin, *New Regulatory Finance,* p. 151. (emphasis added)

134 *See*, Brealey, Myers and Allen, "Principles of Corporate Finance," 12th Edition (2017), pp. 164-165. (clarification added)

135 The arithmetic average of a series can be approximated as:

Arithmetic Average = Geometric Average + Variance of the Series / 2

Because the variance is a positive number, the arithmetic average is larger than the geometric average. *See also*, Leonardo R. Giacchino and Jonathan A. Lesser, "Principles of Utility Corporate Finance," 2011, pp. 133-134.

136 Kroll, Cost of Capital Navigator, accessed July 25, 2024.

137 (7.47% - 5.66%) x Staff's sample average beta of 0.89 = 1.61%.

current capital market conditions (*i.e.*, currently elevated inflation, restrictive monetary policy, geopolitical tensions, *etc.*). It does not reflect the interest rate environment that prevailed during the same time period as the historic market return estimate used in Staff's MRP derivation. It is more appropriate to rely on the historic income-only return on government bonds over the same time period, as *Kroll* does, when estimating the historic market equity risk premium.[138]

Q. How do you respond to Staff's criticisms that your market equity risk premium estimate is "extreme" value?[139]

A. Staff accuses me of using an "extreme" value for the market equity risk premium that "inflates the results of a CAPM model."[140] Specifically, Staff takes issue with calculating the MRP using an arithmetic average and by using a starting point of 1926, which includes post-World-War II economic expansions.[141] I disagree with Staff that my historic MRP estimate is extreme and inappropriately inflates the cost of equity estimates for PGE. As discussed above, using the arithmetic mean is the appropriate methodology when estimating the cost of capital. In addition, it is preferable to use a longer-dated historic MRP to address the specific issue raised by Staff. Longer estimates incorporate data from periods of market growth *as well as* periods of market turmoil. The longer dated historic estimates incorporate more data which reduces the risk of any specific growth or turmoil event influencing the estimate. Using a shorter analysis period for the MRP has the opposite effect.

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[138] Kroll, Cost of Capital Navigator.
[139] Staff/400, Muldoon/12.
[140] *Id.*,12-13.
[141] *Id.,* 13.

Q. Please describe Dr. Kaufman's implementation of the CAPM?

A. Dr. Kaufman adopts my implementation of the CAPM but makes a couple of changes to the inputs. First, he derives beta estimates from the proxy groups that remove certain data around the time of the COVID-19 pandemic and he then adjusts the betas towards the utility average beta, rather than the market beta.[142] He also adopts the Bloomberg forward-looking MRP but replaces the historic MRP with an estimate published by Kroll (5.00%).[143] Lastly, he does not implement standard financial techniques to adjust for differences in financial leverage between the proxy companies and PGE.[144]

Q. Dr. Kaufman argues that *Value Line's* betas are "abnormal" compared to other published estimates. Is this comparison misleading? [145]

A. Yes. Dr. Kaufman argues that *Value Line's* betas are abnormally high because they are not consistent with other published beta estimates. He attempts to illustrate this point by saying that *Value Line*'s beta estimate for PGE is 0.9,[146] whereas Bloomberg, Yahoo, and Zacks report beta estimates of 0.69, 0.59, and 0.58.[147] This comparison is misleading. *Value Line*'s betas are adjusted betas, meaning that they have been corrected based on empirical evidence that shows beta tends to converge towards one over time.[148] Specifically, *Value Line*'s betas are Blume-adjusted betas. In contrast, the betas reported by Bloomberg,[149] Yahoo,[150] and Zacks[151] are not adjusted betas (*i.e.*, they are raw betas). In addition, betas from Yahoo and

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[142] AWEC/200, Kaufman/49-50.
[143] *Id.*, 68.
[144] Exhibit AWEC 204.
[145] AWEC/200, Kaufman/51.
[146] *Value Line*, as of December 31, 2023.
[147] *Id.*, 51.
[148] PGE/600, Figueroa – Liddle/39.
[149] By default, Bloomberg reports Blume adjusted betas.
[150] *See* Yahoo Finance, Key statics definitions, https://help.yahoo.com/kb/finance/SLN2347.html?impressions=true.
[151] *See* Zacks, Portland General, Beta, https://www.zacks.com/stock/chart/POR/fundamental/beta.

Zacks are measured using monthly data whereas *Value Line* betas are measured using weekly data. This comparison is highly problematic and should not be given any weight.

Q. Dr. Kaufman calculates four betas that he alleges reduces the impact of COVID on the beta estimates. What concerns do you have with these estimates?

A. Dr. Kaufman contends that the *Value betas* are abnormally high because they are influenced by certain data during the COVID-19 pandemic, so he re-calculates four alternative betas:

- Excludes any weekly returns that are more than 3 standard deviations from the mean, which results in a sample average raw beta of 0.67;
- Excludes data from February 2020 through April 2020, which results in a raw beta of 0.65;
- Uses monthly rather than weekly return, which results in a raw beta of 0.63; and
- Uses four years of data instead of five years, which results in a raw beta of 0.67.[152]

Dr. Kaufman's beta estimates that selectively exclude market data are highly non-standard and only serve to bias the cost of equity estimates. *Value Line* betas are estimated using five years of weekly return data for the respective proxy company and the market. Yet, Dr. Kaufman seeks to selectively exclude certain market data because he deems them to be "abnormal." The weekly return data are real observations of market return that occurred within the five year estimation period. Dr. Kaufman makes no attempt to show that these returns are mismeasurements of the market return (*i.e.*, that they are not accurate reflections of the systematic risk of utilities under such market conditions). While the market events during the height of the COVID-19 pandemic are not common, this does not mean that they do not accurately reflect the distribution of returns in the period or even going forward, should

[152] AWEC/200, Kaufman/52-53.

another major world event occur. I find Dr. Kaufman's betas estimates are problematic and his methodology biases the estimates.

I also find it more appropriate to use five-year weekly betas, consistent with *Value Line*'s methodology, rather than monthly betas or betas measured over a shorter analysis period. The premise of Dr. Kaufman's argument is that a limited number of market return observations result in "abnormal" beta estimates. However, using weekly returns rather than monthly returns is a superior methodology to mitigating the impact of a limited number of observations. *Value Line*'s five-year weekly betas are based on 260 observations of returns during the analysis period. Using monthly betas decreases the number of observations by about 75% to 60 data points during the analysis period, which gives less statistical power to the estimate and increases the likelihood that an observation could impact the results. Four-year weekly betas are not common and suffer from similar issues as monthly betas in that they have lower statistical power because they rely on fewer observations.

Lastly, Dr. Kaufman compares his alternative beta estimates to "*Value Line* raw betas" in Table 21.[153] However, there appears to be an error in his calculation of the raw betas. For example, *Value Line* reports betas of 1.0 for Black Hills, DTE Energy, Edison International, NextEra and Sempra.[154] Yet, Dr. Kaufman reports a raw *Value Line* beta estimate of 1.11, 0.94, 0.99, 0.87, and 0.96, respectively. This simply cannot be because, by definition, a Blume-adjusted beta of 1.0 is equal to a raw beta of 1.0.[155]

[153] *Id.*, 53.
[154] PGE Exhibit 605-C-01.
[155] Adjusted Beta = 2/3 * Raw Beta + 1/3 * 1 *or* 1 = 2/3 * 1 + 1/3 *1.

Q. Do you agree with Dr. Kaufman's assertion that betas adjusted towards the utility industry average provide a better estimate of PGE's cost of equity?

A. No. *Value Line* betas are Blume-Adjusted, meaning that they have been corrected based on empirical evidence that shows beta tends to converge towards the market beta over time.[156] The Blume Adjustment was developed by Professor Marshall Blume and well-established academic evidence shows that the adjustment improves the forward-looking predictive power relative to raw historic betas. Dr. Kaufman alleges that it is inappropriate to adjust raw utility betas towards the market beta, but instead should be adjusted towards the utility industry average beta.

Dr. Kaufman's beta adjustments to the industry average beta is conceptually similar to the Vasicek adjustment. The Vasicek method weights the raw beta and the "true" beta according to the standard error of the estimates.[157] The goal of the Vasicek adjustment is similar to the Blume adjustment in that they try to adjust betas for their mean reversion tendencies. However, the problem with Dr. Kaufman's beta adjustment (and the Vasicek adjustment) is that it requires an estimate of the "true" beta for the industry, which is not known. Dr. Kaufman departs from the Vasicek methodology by estimating an industry average beta by observing five-year monthly betas for the proxy sample over the prior 10 years. He makes no attempt to estimate the true beta of the utility industry (*i.e.*, he just relies on the proxy sample) or demonstrate that the proxy group is representative of the "industry"

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[156] PGE/600, Figueroa – Liddle/39. *See also* Marshall E. Blume, "Betas and Their Regression Tendencies," *Journal of Finance*, Vol. 30, No. 3, June 1975, pp. 785-795.

[157] O. A. Vasicek, "A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas," Journal of Finance 28, 1973, pp. 1233-1239.

beta. Further, academic research has found that industry adjusted betas do not perform significantly better than Blume-adjusted in terms of forecasting power.[158]

He further departs from the Vasicek methodology by ignoring the Vasicek formula and instead adapting the Blume adjustment formula to use his industry beta.[159] The Blume Adjustment formula was derived from Professor Blume's regression equation coefficients which suggested a weight of 2/3 on the raw beta and 1/3 weight on the market beta of 1.0. That is to say, his adjusted beta methodology is highly non-standard and is an amalgamation of two different adjustment mechanisms. I find that Dr. Kaufman's industry adjustment betas are not appropriate and not commonly relied upon in U.S. regulatory settings.

Q. Are Blume Adjusted betas commonly used?

A. Yes. Services such as Bloomberg and *Value Line* that cater to investors apply the Blume adjustment to their off-the-shelf betas. While Bloomberg allows users to manually specify estimation parameters, the *default setting* is an adjusted beta. *Value Line* only provides adjusted betas. Furthermore, the CFA curriculum teaches its candidates to adjust raw betas because doing so results in a more accurate prediction of future betas.[160] Further, the CFA Institute's curriculum only teaches candidates to adjust betas using the Blume Adjustment.

Blume Adjustments are commonly relied upon in regulatory settings as well. While Dr. Kaufman says that the Commission previously ruled against the use of adjusted betas,[161] he ignores the fact that Staff's standard methodology relies on *Value Line* betas in its CAPM and for estimating financial leverage adjustments in the DCF.[162] Other regulatory

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[158] Dimson and Marsh, 1983.
[159] AWEC/200, Kaufman/63.
[160] CFA Institute Curriculum Level II Vol. 4, p. 71.
[161] AWEC/200, Kaufman/60.
[162] Staff Exhibits 402 and 405.

jurisdictions, including FERC[163] and the New York Public Service Commission[164] also use Blume-adjusted *Value Line* betas in their standard cost of equity methodologies. Other regulatory Commissions, such as Michigan,[165] Illinois,[166] Montana,[167] and North Carolina[168] are often presented with *Value Line* betas, which the Commissions consider in making their allowed ROE determinations.

Q. What concerns does Dr. Kaufman raise regarding your historic market equity risk premium estimates?

A. Dr. Kaufman argues that the historic MRP is a poor predictor of future market performance because it relies on the arithmetic average growth rather than the geometric average growth.[169] He further argues that my historic and forward-looking MRP estimates are above other published estimates from various sources that range from 3 to 6 percent.[170] He also argues that the MRP derived from the FERC cost of equity methodology is not relevant because it does not represent decisions made by investors.[171] Lastly, the reliance on the geometric average MRP downwardly biases the expected MRP.[172]

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163 FERC Order 569-A.
164 New York State Public Service Commission, "Staff Finance Panel Testimony," Case 19-E-0066, May 2019, p. 102, lines 2-4.
165 Michigan Public Service Commission, Direct Testimony of Joseph Ufolla, Case No. U-20642, May 24, 2020
166 Illinois Commerce Commission, Direct Testimony of Rochelle M. Phipps, ICC Staff, Docket No. 21-0098, May 18, 2021.
167 Montana Public Service Regulation, Order 7575c, Docket No. D2017.9.80, September 25, 2018.
168 North Carolina Utilities Commission, Order, Docket No. E-2, Sub 1300, August 18, 2023
169 AWEC/200, Kaufman/65.
170 *Id.*, 64-65.
171 *Id.*, 65.
172 Leonardo R. Giacchino and Jonathan A. Lesser, "Principles of Utility Corporate Finance," 2011, pp. 233-234.

Q. Do you agree that the historic MRP is a poor predictor of future returns because it does not use the geometric average growth?

A. No. Academic finance is clear that the arithmetic mean is the appropriate metric when estimating the cost of capital.[173] As discussed at length above, geometric returns are appropriately used to evaluate the historic performance of a stock portfolio (*i.e.*, the average annual achieved return over some time period). However, when estimating the cost of capital, which is a forward-looking concept, the goal is to estimate the rate of return that investors expect. Reliance on a historic MRP estimated using the geometric mean in a cost of capital analysis is inappropriate and will downwardly bias the MRP estimate.

Q. What concerns do you have about the alternative MRP estimates cited by Dr. Kaufman?

A. Dr. Kaufman presents alternative MRP estimates from a variety of sources, including financial institutions, academic papers, and surveys.[174] Several of the studies Dr. Kaufman includes in his testimony are outdated and do not reflect the recent and economic financial uncertainty, such as elevated levels of inflation, monetary policy changes, and geopolitical tensions. For example, Dr. Kaufman provides several investor and finance professional surveys in Table 26, the newest of which is over four years old, others are taken from the time of the global financial crisis (February 2007 and March 2007), and the rest are form the 2010's.[175] In Table 25, he presents "recent" equity risk premium (*i.e.*, MRP) estimates, many of which are several years old (*e.g.*, 2018, 2020, 2021). Reliance on outdated MRP estimates is not reflective of current market conditions nor the return required by investors to hold non-risk-free assets.

[173] *See* Morin as well as Brealey, Myers, and Allen quoted above.
[174] AWEC/200, Kaufman/66-71.
[175] *Id.*, 69-70.

In addition, he cites to Professor Damodaran's 2022 MRP estimate of 5.13% as additional support to his choice of the MRP.[176] Notably, for some reason, he does not provide Damodaran's latest MRP estimate, published in March 2024, which shows the quoted MRP is now 5.23%.[177] While I do not endorse Professor Damodaran's estimate, the updated estimate suggests that the MRP has recently increased. Another indicator of a higher risk premium required by investors is the recent spike in VIX to as high as 65.73 on August 5, which is the highest level of volatility since March 2020.[178]

Q. What concerns do you have with the alternative MRP estimates that are based on survey data?

A. Most of Dr. Kaufman's alternative MRP estimates are derived from survey data. Specifically, Merrill Lynch's Global Funds Manager survey; survey of finance and economics professors, analysts, and managers of companies; CFA 2021 ERP Forum Survey; and the Graham and Harvey survey of CFOs.[179] Survey data can be problematic and should not be given any weight by the Commission. As a study from Professor Ibbotson noted:

> When using this [survey] method, one attempts to obtain the estimates from the market participants themselves. But there are a number of problems with this approach. Most of these investors have no clear opinion about the long-run outlook. Many of them have only very short-term horizons. Individual investors often exhibit extreme optimism or pessimism and make pro-cyclical forecasts…[180]

Professor Ibbotson further expands on the points above by noting there are problems with replicability, the determination of the horizon over which the forecast is made, and the very

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[176] *Id.*, 70-71.
[177] Aswath Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2024 Edison," March 5, 2024, p. 41, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4751941
[178] Cboe, VIX, accessed August 6, 2024, https://www.cboe.com/tradable_products/vix/.
[179] *Id.*, 67, 69-70.
[180] Roger G. Ibbotson, "The Equity Risk Premium," published in Rethinking the Equity Risk Premium, Research Foundation of CFA Institute, December 2011, p. 20 (notes omitted).

large variation in forecasts amongst participants. I agree with Professor Ibbotson for these reasons and find that survey based MRP estimates lack reliability and should be disregarded.

It is also worth noting that in Professor Fernandez' IESE Business School survey cited by Dr. Kaufman,[181] the author specifically cautions against using the survey data to estimate the cost of equity—he says the average of the MRP survey estimates "cannot be interpreted as the [required equity premium] of the market nor as the [required equity premium] of a representative investor."[182] In addition, the Professor Damodaran study cited by Dr. Kaufman[183] states that "very few practitioners seem to be inclined to use the numbers from these surveys in computations."[184] One reason is that survey premiums are sensitive not only to whom the question is direct but also how the question is asked.[185] A second reason provided by Professor Damodaran is that studies looking at the efficacy of survey premiums indicate that *if* they have any predictive power, it is in the wrong direction.[186]

Q. Dr. Kaufman relies on Kroll's "normalized" MRP in his implementation of the CAPM.[187] Is this a reliable MRP estimates to use when estimating the cost of capital?

A. No. Dr. Kaufman cites Kroll's "normalized" MRP of 5.0%, which he ultimately relies upon in his implementation of the CAPM.[188] The Kroll "normalized" MRP is inconsistent with the well-established inverse relationship between interest rates (*i.e.*, the risk-free rate) and the market equity risk premium: as interest rates increase (decrease), the MRP decreases

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[181] AWEC/200, Kaufman/70.

[182] Pablo Fernandez, Teresa Garcia, Javier Fernandez Acin, "Survey: Market Risk Premium and Risk-Free Rate used for 95 countries in 2022," May 25, 2022, p. 9, (clarification added) https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3803990&download=yes.

[183] AWEC/200, Kaufman/70.

[184] Aswath Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2022 Edison," March 23, 2022, p. 27, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4066060.

[185] *Ibid*.

[186] *Ibid*.

[187] AWEC/200, Kaufman/68. *Note,* Dr. Kaufman also relies on my forward-looking Bloomberg MRP estimate.

[188] *Ibid*.

(increases), all else equal. There is significant evidence from academic research that supports this inverse relationship. As Dr. Morin summarizes in his textbook:

> This is particularly true in high inflation environment. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the average of common stocks, which are partially hedges from the ravages of inflation. This phenomenon has been termed as a "lock-in" premium. Conversely, in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fear as loss of earnings power dominate, the risk differential will widen and hence the risk premium will increase.
>
> Published empirical studies demonstrated that risk premiums vary inversely with the level of interest rates, rising when rates fell and declining when interest rates rose. Studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), and Morin (2020), and others demonstrate that beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and declining when rates rose.[189]

Looking to the MRP and risk-free rates relied on by Kroll relative to the long-term historic estimates highlights the inconsistencies.

Figure 5: MRP and Risk-Free Rate Relationships

	Kroll's Long-Term Historic Estimate 1926 - 2023	**Kroll's Current "Normalized" Estimate** June 2024
Risk-Free Rate	4.87%	3.5% (-1.37%)
Market Risk Premium	7.17%	5.0% (-2.17%)

Kroll reports the historic long-term (1926-2023) MRP estimate is 7.17%, which is measured relative to a historic long-term (1926-2023) income only return on 20-year government bonds of 4.87%.[190] Whereas, Kroll's current normalized MRP estimate is 5.0% and its current normalized risk-free rate is 3.5%.[191] That is, Kroll's current normalized MRP

[189] Roger A. Morin, New Regulatory Finance, 2006, p. 128
[190] Kroll, U.S. Cost of Capital Navigator.
[191] Kroll, "Kroll Recommended U.S. Equity Risk Premium and Corresponding Risk-Free Rates to be Used in Computing Cost of Capital: January 2008 – Present", June 5, 2024,

and risk-free rate have declined together, relative to Kroll's long-term historic estimates, by 2.17% and 1.37%, respectively, rather than moving in opposite directions as predicted by the relationship between interest rates and the MRP. For this reason, Kroll's current "normalized" MRP estimate is problematic and should not be given any consideration. I continue to find Kroll's historic long-term estimate (1926-present) to be a more appropriate estimate of the MRP.

Q. How do you respond to Dr. Kaufman's argument that the MRP derived using the FERC methodology is not representative of investors' expectations?

A. I disagree with Dr. Kaufman's conclusion and continue to find it appropriate to consider the FERC-based MRP when estimating the ROE for regulated utilities. One of the core principles of the Fair Return Standard established by the U.S. Supreme Court in the *Hope* and *Bluefield* cases is that the return to the equity holder should be commensurate with returns on investments in other enterprises having corresponding risks.[192] Investors can and do observe the allowed returns and capital structures awarded to regulatory entities in different regulatory jurisdictions. The decisions of investors on how to invest or allocate capital amongst regulated utilities in various jurisdictions are influenced by such comparison. The FERC relies on its prescribed methodology to calculate the MRP when determining the allowed ROEs for the companies that it regulates, which are readily available to investors. Therefore, I find that the FERC-derived MRP is informative when determining the risk-adjusted return required by investors to invest in regulated utilities, like PGE.

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https://www.kroll.com/en/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates

[192] *Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope"), at 603.

<u>Impacts on the CAPM-Based ROE Estimates</u>

Q. Could you please illustrate the impact of your various concerns regarding Staff's CAPM on their ROE estimates?

A. Yes. In Figure 6 below, I make three standard adjustments to Staff's CAPM.[193] First, I replace Staff's current risk-free rate with the forecasted risk-free rate that is more reflective of market conditions when rates are expected to be in effect. Second, I adjust Staff's model to exclude Exelon from the Company Screen average ROE because it does not have a *Value Line* beta (*i.e.*, its beta is not zero as reported by Staff, which resulted in an erroneously low ROE estimate in Staff's model). I do not make further adjustments to Staff's betas in this analysis; in the following section I address the impact of financial leverage adjustments on Staff's ROE estimates. I replace Staff's 30-year MRP estimate measured using the geometric average with the historic, long-term (1926-present) MRP estimate from Kroll measured using the arithmetic average. Notably, Kroll's historic, long-term estimate of 7.17% is below Kroll's 30-year historic MRP (consistent with Staff's estimation period) measured using an *arithmetic* average, which is 7.47%. I also adjust Staff's proxy sample in the same manner as described above in the DCF corrections.

These standard corrections show that Staff's CAPM estimates are downwardly biased by about 210 basis points. The corrected results are supportive of PGE's requested allowed ROE of 9.65%.

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[193] For clarity, just because I do not make an adjustment to a CAPM input does not signify endorsement of the value or methodology to derive the value.

Figure 6: Corrected Staff CAPM Results[194]

	Original		Corrected	
	Staff Screen	Company Screen	Staff Screen	Company Screen
Risk-free Rate	4.35%	4.35%	4.20%	4.20%
Market Risk Premium	4.73%	4.73%	7.17%	7.17%
Beta (Sample Average)	0.92	0.89	0.92	0.93
CAPM	**8.7%**	**8.6%**	**10.8%**	**10.8%**
Difference			**2.1%**	**2.2%**

Q. What is the impact of your concerns on Dr. Kaufman's CAPM implementation and the resulting ROE estimates?

A. As discussed above, I disagree with Dr. Kaufman's revised beta estimates and the Kroll's current "normalized" MRP estimate. I also disagree with his decision to disregard the standard financial techniques to adjust for differences in financial leverage between the proxy companies and PGE. Given that Dr. Kaufman adopts my CAPM and then makes these adjustments, I find that these adjustments downwardly bias his CAPM estimates by 300 to 340 basis points relative to my reasonable range of CAPM estimates.[195]

<u>Financial Leverage Adjustments</u>

Q. What concerns do you have with Dr. Kaufman's analysis of capital structure impacts on the cost of equity?

A. Dr. Kaufman criticizes and ultimately throws out the financial leverage adjustments in my model because of his ill-founded perception that the change in magnitude in the estimated ROE is not commensurate with the change in magnitude of the equity ratio for the proxy companies in the DCF. This is based on a comparison of the estimated ROEs for proxy

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[194] PGE Exhibit 1800C-01.

[195] Rejecting Dr. Kaufman's adjustments to my CAPM implementation would restore the CAPM-based ROE estimates as presented in PGL Exhibit 603 and 605C.

companies with market value equity capital structures above or below the sample average.[196] This analysis is atheoretical and problematic, and therefore should not be given any weight.

Dr. Kaufman's analysis relies on a comparison of the estimated ROE's *prior* to any adjustment for financial leverage. The implicit assumption is that each of the proxy companies are identical in every other aspect, except for capital structure. However, this is divorced from reality. For example, the betas in the CAPM reflect differences in systematic risk between the proxy companies (*i.e.*, market risk) and the growth rates and dividends in the DCF reflect the business operations of the proxy companies. Simply comparing the estimated ROEs and market value capitals structures does not isolate the impact of financial leverage. That is the point of and why it is important to implement these adjustments, so that the ROE estimates are on a comparable financial-risk-adjusted basis.

Q. Dr. Kaufman argues that it is more appropriate to use the book value capital structure when making financial leverage adjustments.[197] How do you respond?

A. I disagree with Dr. Kaufman that the book capital structure is the most relevant metric for financial leverage adjustments. Financial risk is a large topic in financial economics. The principle that financial leverage amplifies the variability of equity returns and thereby increases the financial risk to equity investors is a firmly established core principle of corporate finance. It is directly connected to the Modigliani Miller proposition that, except as influenced by the tax-deductibility of debt and the cost of financial distress, the value of a firm's assets is independent of its choice of financing.

Standard cost of equity estimation methods, including the CAPM and DCF, express a company's cost of equity in percentage terms of equity at the observed market capital

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[196] AWEC/200, Kaufman/48.
[197] *Id.*, 48-49

structure. The DCF Model (and CAPM) rely on market data to estimate the cost of equity for the proxy companies, so the results reflect the value of the capital that investors hold during the estimation period (*i.e.*, the market values). Financial economics simply does not leave any doubt that the cost of equity increases with financial leverage and that the relevant measure of financial leverage depends on market value. As Professors Berk and DeMarzo state:

> The levered equity return equals the unlevered return, plus an extra "kick" due to leverage…The amount of additional risk depends on the amount of leverage, **measured by the firm's market value debt-equity ratio, D/E.**[198]

Brealey, Myers, and Allen also state:

> Modigliani and Miller's (MM's) famous proposition 1 states that no combination is better than any other—the firm's overall **market value** (the value of all its securities) is independent of capital structure.[199]

In my testimony, I rely on the market value of the proxy companies in the CAPM and DCF models to adjust for differences in financial leverage. I then apply this to PGE's requested 50.0% equity capital structure, which is the subject of cost-of-service regulation in this proceeding. Since the Risk Premium model is based on book values, the relevant leverage for this methodology is book value based.

Q. Do you have any other observation about Dr. Kaufman's critiques of your financial risk adjustments?

A. Yes. Dr. Kaufman does not raise any concerns regarding the merit of performing financial leverage adjustments. In fact, he says, "capital structure can affect the risk that equity investors face. All else equal, a firm with a lower equity faces [*sic*] greater risk than a firm with a higher equity ratio."[200] However, instead of attempting to perform his own version of financial

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[198] Berk & DeMarzo, "Corporate Finance," 3rd Edition (2013), p. 489 (emphasis added).
[199] Brealey, Myers & Allen 2017, p. 453 (emphasis added).
[200] AWEC/200, Kaufman/47.

leverage adjustments, he simply dismisses them based on a faulty analysis, which, as a result, results in ROE estimates that would not provide a fair, risk-adjusted return.

It is worth noting that Dr. Kaufman's recommended capital structure (44.6% equity) would increase the financial risk and thus investor required return compared to the Company's requested capital structure (50.0% equity). All else equal, the lower equity capital structure would increase Dr. Kaufman's DCF results from 9.3% to 10.7% (single stage) and 8.9% to 10.0% (multi-stage).[201] Further calling into question the reasonableness of his recommended ROE.

Q. What concerns do you have with Staff's implementation of the Hamada Adjustment in its DCF model?

A. While I agree with Staff that differences in financial leverage are important and can impact the cost of equity, I have two concerns with Staff's implementation of the Hamada Adjustment. First, the use of the Hamada Adjustment in the DCF is non-standard because beta—the focus of this financial leverage adjustment—is not an input to the DCF calculation. Applying the Hamada Adjustment to the CAPM and the after tax weighted average cost of capital to the DCF would be more appropriate.

Second, Staff calculates the Hamada Adjustment based on the proxy companies' book capital structure rather than their market value capital structure. As discussed above, the DCF Model (and CAPM) rely on market data to estimate the cost of equity for the proxy companies, so the results reflect the market value of the equity capital held by investors. Therefore, it is more appropriate to use the market value capital structure when adjusting for financial leverage. It is also worth noting that the average market value capital structure for the proxy

[201] PGE Workpaper – ROE Corrections_CONF.

sample has a higher proportion of equity than Staff's estimated average book capital structure,[202] which, all else equal, would result in a higher financial risk-adjusted ROE estimate at PGE's requested 50.0% equity capital structure.

Q. What are the impacts on Staff's DCF results if you make these changes?

A. If I apply the after tax weighted average cost of capital using market value capital structures to the DCF, rather than the Staff's Hamada Adjustment, Staff's ROE estimates increase by approximately 62 to 66 basis points. Specifically, the ROE estimates from Staff's Model X increase from 9.02% (without Staff's Hamada) and 8.90% (with Staff's Hamada) to 9.52%. Similarly, the ROE estimates from Staff's Model Y increase from 9.32% (without Staff's Hamada) and 9.20% (with Staff's Hamada) to 9.86%. Next, I apply the Hamada Adjustment, using market value capital structures, to Staff's CAPM. The ROE estimates from Staff's CAPM increase from 8.7% to about 9.2%.

Risk Premium Model

Q. How do you respond to Dr. Kaufman's criticisms of your risk premium model?

A. Dr. Kaufman argues that the Risk Premium Model does not reflect the return that investors can expect because it is based on the utilities' book value of equity.[203] He argues that the Risk Premium Model should be adjusted to account for the price-to-book ratio of utilities. Lastly, he argues that the model fails to reflect the proxy sample.[204] I disagree with Dr. Kaufman – his arguments miss the point of what the Risk Premium Model is meant to accomplish.[205]

The Risk Premium Model estimates the cost of equity from regulated entities as opposed to holding companies, so that the relied upon figure is directly applicable to a rate base.

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[202] *See*, PGE Exhibit 605C-01.
[203] AWEC/200, Kaufman/72-73.
[204] *Id.*, 74.
[205] *Id.*, 73.

Therefore, applying a price-to-book ratio is not necessary. In addition, the allowed returns are readily observable by market participants, who will use allowed ROE decisions as an input in making their investment decision. To attract capital from investors, PGE must offer a return that is on equal terms with other utilities with similar risk profiles. The Risk Premium Model measures the premium that investors in other regulated utilities have access to and then uses this premium to derive a cost of equity using the forecasted-risk free rates that are expected to prevail when PGE's rates are in effect. Importantly, the underlying data for the model is <u>not</u> limited to ROE decisions for the proxy group because investors are able to observe the returns offered in other rate case decisions. Specifically, the estimated risk premium is estimated based on the 1,082 rate case decisions for vertically integrated utilities since 1990, including those for the proxy companies.[206] While the Risk Premium Model does not have the theoretical support that the CAPM and DCF models do, it does provide a direct benchmark for the return available to investors who invest in other regulated electric utilities, consistent with the Fair Return Standard.

Ignoring the results from the Risk Premium Model disregards the information available about returns available to equity owners holding assets with commensurate risk, as required by the Fair Return Standard. Therefore, the results of the Risk Premium Model serve as a check on the reasonableness of the ROE estimates from the CAPM and DCF estimates.

[206] PGE Exhibit 605C-03.

D. Response to Other Critiques

Ms. Perry's Recently Allowed ROE Analysis

Q. What is your reaction to Walmart witness', Ms. Perry's, comparison to recently allowed ROEs and her recommendation for PGE's allowed ROE based on this analysis.

A. Ms. Perry argues that PGE's requested ROE is above recently allowed ROEs for electric utilities in Oregon and cross the country.[207] She points to the allowed ROEs that the Commission approved for PGE in 2022 and 2023 and for PacifiCorp in 2022, which were all 9.50%.[208] In addition, she compares PGE's requested ROE to the average and median ROE for electric utilities as well as vertically integrated utilities from 2021 to 2024.[209] I have several concerns with her analysis.

First, Ms. Perry's own analysis shows that the allowed ROEs for electric utilities have been on an upward trend since 2021, reflecting heightened uncertainty in economic and financial conditions over this time period.[210] However, I find apparent inconsistencies in her reported averages based on Regulatory Research Associates' Past Rate Case database. Excluding limited issue riders, the average (median) allowed ROEs for vertically integrated electric utilities was 9.53% (9.50%) in 2021, 9.75% (9.70%) in 2022, 9.80% (9.70%) in 2023, and 9.77% (9.83%) in 2024 to date.[211] These are higher than the values reported by Ms. Perry and shows that PGE's requested ROE is consistent with allowed ROEs awarded to vertically integrated electric utilities since 2022. This finding is further supported by Figure 1 in

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[207] Walmart/100, Perry/8.
[208] *Id.*, 9.
[209] *Id.*, 10-12.
[210] *See* Walmart/100, Perry/11.
[211] S&P Capital IQ Pro, Past Rate Cases. *See* PGE Exhibit 1800C-02.

Ms. Perry's testimony, which shows that PGE's requested ROE is near the middle of authorized ROEs for vertically integrated electric utilities since 2021.[212]

Second, Ms. Perry's comparison of PGE's requested ROE to the allowed ROE for other utilities is simplistic and ignores differences in capital market conditions since the time of the underlying decisions. It also ignores differences in business risks between Oregonian utilities, U.S. electric utilities, and PGE. While looking to historic allowed ROEs can be helpful, they must be placed in the appropriate context and they should not be solely relied upon to set the allowed ROE for PGE without consideration of PGE's individual business characteristics and risks.[213] Doing so would fail to meet the guiding principles of the fair return standard.[214]

<u>Business Risk and ROE Implications of OPUC's Witness', Mr. Beitzel's, Proposal</u>

Q. Mr. Beitzel's raises concerns regarding the timing and size of PGE's request for a general rate revision and discusses the merits of related trackers and adjustment mechanisms proposed by PGE, Staff, and CUB.[215]

A. Mr. Beitzel's argument is premised on PGE's "unwillingness to absorb any regulatory lag for major resources and infrastructure investments,"[216] such as the Company's Constable and Seaside battery facilities.[217] Mr. Beitzel also does not support PGE's proposed Investment Recovery Mechanism ("IRM"), which is a capital tracker that would allow PGE to recover costs in between general rate cases, or the use of the Renewable Adjustment Clause ("RAC")

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[212] Walmart/100, Perry/12.

[213] *Note*, I rely on the same S&P Capital IQ Past Rate Cases database in the implementation of my Risk Premium Model. I use the database to estimate the premium to apply to the forecasted risk-free rate to estimate the allowed ROE for PGE (10.5%). However, for clarity, I do not rely on the Risk Premium analysis to arrive at my recommended ROE – I simply rely on it as a check to the reasonableness of the CAPM and DCF-based estimates.

[214] *See* PGE/600, Figueroa - Liddle, Technical Appendix, Section III.

[215] Staff/100, Beitzel/1.

[216] *Id.*, 4.

[217] *Id.*, 1-2.

tracker to recover these costs.[218] Instead he discusses several alternatives to PGE's proposal. One proposal, put forth by CUB, is to use the ROE "as a throttle to control the frequency and timing of general rate cases" by finding that frequent rate cases are sufficient to reduce regulatory lag and reduce financial risk in terms of credit metrics.[219] Alternatively, Mr. Beitzel proposes that if the Commission adopts the IRM, that PGE should be locked out of a general rate case for three years.[220]

Mr. Beitzel raises several troubling arguments that relate to PGE's business risk and ultimately its fair risk-adjusted rate of return. According to the Fair Return Standard, a fair return is one that is sufficiently attractive for investors to forego the opportunity to earn a return from an alternative investment of comparable risk. In the financial sense, risk is related to the amount of uncertainty or variability of returns. The implication of Mr. Beitzel arguments is that PGE should accept some amount of regulatory lag (*i.e.*, uncertainty of returns) by foregoing a capital tracker mechanism or being locked out of a general rate case, without any consideration for the impact on PGE's business risks or the fair rate of return.

Capital trackers or other cost recovery mechanisms generally mitigate business risks by reducing regulatory lag and/or increasing cost recovery certainty for prudently incurred costs. Many of the vertically integrated electric utilities in the proxy companies have such mechanisms.[221] All else equal, increasing PGE's regulatory lag would increase its business risk and the risk-adjusted return required by investors. Failure to mitigate regulatory lag in a

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[218] *Id.*, 6-7.
[219] *Id.*, 4-5. Note, Credit metrics and resulting credit ratings reflect the risks to a company's debt investors. They do not reflect the risk to equity holders. Mr. Beitzel's focus on credit metrics is misplaced.
[220] *Id.*, 6.
[221] S&P Capital IQ, "Adjustment Clauses: A state by state overview," July 17, 2022.

manner similar to the proxy companies without upwardly adjusting PGE's allowed ROE likely would result in failing to meet the Fair Return Standard.

Q. Does the fact that you have not addressed all the issues in Staff and the Intervenor's testimonies indicate that you agree?

A. No, it does not.

Q. Does this conclude your testimony?

A. Yes.

IV. Capital Structure

A. Summary

Q. Please summarize your position on PGE's cost of capital.

A. We continue to believe that a 50/50 debt to equity ratio is appropriate. When we evaluate capital structure, we consider several factors including:

- The need to maintain its financial strength, flexibility, and adequate liquidity;
- PGE's ability to maintain reliable and economical access to the capital markets; and
- Keeping the cost of capital to customers and shareholders at a low and reasonable level.

As discussed in our opening testimony, PGE Exhibit 600, our 50/50 capital structure recommendation is supported by utility industry peer data—a valuable resource that provides a benchmark for the standard amount of financial risk that is reasonable within the utility industry. In addition, the equity portion helps offset the leverage and risk that PGE will likely encounter over the next few years and a capital structure at 50% equity and 50% debt helps offset the leverage imputed by the rating agencies on PGE's purchased power.

Q. Does PGE's actual capital structure reflect 50% for equity and debt at all times?

A. No. As shown in PGE Exhibit 1801, while PGE's long-term goal continues to be to maintain our capital structure at 50% equity and 50% debt, the actual equity ratio does fluctuate around the 50% target level, due to the timing and size of debt and equity issuances.

Q. Can you briefly explain why for ratemaking purposes PGE uses a long-term capital structure of 50% long-term debt and 50% common equity?

A. PGE's regulated capital structure was first set in 2007 at 50% equity and 50% debt in UE 180, Order No. 07-015. Staff noted that this ratio mirrored the common equity ratio for Staff's sample and that PGE had in other forums expressed a projected level of 50%. The Commission adopted this reasoning and further noted that it was more in line with PGE's projected equity level. In general rate cases after UE 180, PGE has provided its historical and forecasted capital structure in its opening testimony.[222] The stipulations reached in PGE's last five general rate cases have reaffirmed the 50/50 regulated capital structure.

Q. Has PGE issued any equity since it submitted opening testimony?

A. Yes. We drew the $78 million of equity issued under the forward agreement mentioned in our Opening Testimony. We entered into additional forward sale agreements for 5.1 million shares (~$218 million) and intend to draw that remaining equity during 2024. PGE also put a new $400 million At-the-Market equity program in place to further our ability to raise equity to support investment on behalf of customers and our balance sheet strength.

Q. Do parties testifying on this matter support PGE's proposed capital structure?

A. Most do. OPUC Staff recommend support for PGE's proposed 50/50 capital structure. CUB proposes no changes. AWEC makes an alternative, unsupported recommendation.

B. Response to Staff, AWEC, and CUB on Capital Structure

Q. Does PGE agree with Staff's recommendation?

A. Yes. Staff highlights the appropriateness of using a target capital structure, Staff notes that while PGE may be relying more heavily on debt financing in the near-term, the Company targets a 50% equity capital structure over the long-run and is expected to arrange new equity offerings to bring its capital structure towards 50% equity. Staff also cites the Commission's statement from the PacifiCorp general rate case[223] that a 50/50 capital structure is considered

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[222] UE 197, Order No. 09-020; UE 215, Order No. 10-478; UE 262, Order No. 13-459; and UE 283, Order No. 14-422.; UE 294, Order No. 15-356.

[223] Docket UE 374, Order No. 20-473 at 24.

optimal for ratemaking to "strike a balance between the interests of ratepayers and the interests of investors."[224]

Q. What is AWEC's capital structure recommendation?

A. AWEC recommends using PGE's actual 2023 capital structure of 44.6% equity. AWEC argues that hypothetical capital structures should only be authorized when the hypothetical equity ratio is below the actual ratio, to incentivize the company to align its actual capital structure.

Q. What reasoning does AWEC provide for its recommendation?

A. AWEC asserts that PGE's actual equity ratio has been consistently lower than the authorized 50% since 2019 and that, since a lower actual equity ratio leads to higher returns for shareholders, PGE has an incentive to maintain its actual equity ratio below the long-run 50% target. AWEC calculates that using PGE's proposed hypothetical capital structure increases ratepayer costs by $33 million per year and results in a $20 million windfall profit to shareholders.

Q. Is AWEC's Table 15: Historic Equity Ratios[225] an accurate representation of PGE's actual regulated equity ratios from 2019 through 2023?

A. No. Contrary to AWEC's proposal on rate base, which shows their recognition of the use of an average of averages, in this instance AWEC is opportunistically choosing to use year-end accounting ratios and ignores that actual regulated earnings as calculated in the utilities' annual results of operations report are determined using the year's actual average of averages of equity through the year. Table 2 show these values.

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[224] Staff/400, Muldoon/5.
[225] AWEC/200, Kaufman/35.

Table 2
Actual Regulated Average Equity

	2019	2020	2021	2022	2023
Regulated Average Equity	51.4%	50.2%	48.8%	46.8%	47.4%

Q. Is AWEC's recommendation appropriate?

A. No. As mentioned about, AWEC inappropriately uses a year-end equity value, which is not used anywhere within the determination of regulated earnings. Given the size and timing of debt and equity issuances, PGE will rarely have a capital structure that is exactly 50/50 at a single point in time, which is why it is most appropriate to target a 50/50 ratio over time, which is what PGE has done. Table 3 below shows that PGE has remained in-line with its long-term target of achieving a 50/50 capital structure and PGE has held to this average since its capital structure was first set to 50/50 in 2007.[226]

Table 3
Mean of Average Regulated Equity

	10YrAvg	Since 2007
Long-Term Debt	50.3%	50.1%
Common Equity	49.7%	49.9%

Q. AWEC states that PGE is "currently incentivized to maintain its actual equity ratio below the long run target" and then recommends that the "hypothetical" structure should not be used. How does PGE respond to this argument?

A. AWEC posits a false dichotomy as to why an actual year-end value should be used and fails to consider critical factors regarding capital structure which affect customers and shareholders. Contrary to AWEC's position, PGE is incentivized to maintain a 50/50 capital structure over the long term because it provides lower cost of capital and, thereby, lower cost to finance investments on behalf of customers. A 50/50 capital structure also affords PGE and

[226] See PGE Exhibit 1801.

its customers a degree of financial strength to temporarily absorb events such as COVID, wildfires, and major weather events such as ice storms. For example, over the period from 2019 to early-2024 – the period AWEC disapproves of PGE's lower equity, we have had the following major events[227]:

- $29 million – Labor Day Wildfire Event
- $70 million – 2021 Emergency Ice Storm Event
- $21 million – COVID Pandemic
- $43 million – January Ice Storm Event
- $75 million – January Reliability Contingency Event

Having a strong balance sheet to be able to pay for these events has been critical and also enabled PGE and parties to remain flexible on the period of recovery to minimize impact to customers' prices. As of June 30, 2024, PGE has $218 million of unrecovered costs related to the events above which continue to put pressure on PGE's balance sheet. PGE has another $47 million of unrecovered costs related to various activities including environmental remediation, wildfire mitigation, amongst others[228]. To be clear, deferrals and use of the balance sheet has virtues but it is important to consider the extent of use, especially when parties are proposing severe modification of policy seemingly without consideration for this key element.

Q. Have the ratings agencies taken note of this situation?

A. Yes, in particular, Moody's has noted that while cost recovery is supported, timeliness of recovery is a challenge. In June 2024, Moody's put PGE on Negative Outlook, which is a

[227] Amounts listed at the original value of deferral, net of any earnings test or other reductions, and exclude amortization & interest.

[228] PGE identified net regulatory assets and liabilities on its books that are earning a debt return (or no return) as of June 30, 2024.

precursor step for a potential credit rating downgrade. As noted above, PGE is taking steps to improve its equity capitalization and key credit metrics and it will be an important signal should the Commission choose to either support the existing capital structure or make a change.

Q. Does AWEC provide any empirical evidence supporting their claim that PGE is overearning?

A. No. Despite an apparent dislike for hypotheticals (re: capital structure), AWEC only provides hypothetical evidence supporting their claim that customers are harmed. As evidenced by PGE's Results of Operations reports PGE is underearning relative to our authorized ROE in each of the years cited by AWEC. As shown on Table 4 below, PGE's 2023 regulated ROE was 7.18%. Additionally, AWEC's assertion that customers lack control and shareholders have many tools to control capital structure is simply false – management is responsible for managing the capital structure.

Table 4
Mean of Average Regulated Equity

	10YrAvg	Since 2007
Long-Term Debt	50.3%	50.1%
Common Equity	49.7%	49.9%

Q. How do you respond to AWEC's claims that credit metrics could be supported in less costly ways? Does AWEC support their claims?

A. AWEC provides no support for their claims. They suggest that applications to recover deferrals, changes to depreciation rates, or improved cost control are all ways to improve cash flow by avoiding the tax burden with the alleged "windfall profits." In essence, AWEC is proposing higher depreciation rates and faster deferral cost recovery, both of which have direct consequences for customer prices.

PGE believes that depreciation rates are well-examined and appropriately set through depreciation studies and general rate case proceedings and that deferral cost recovery is thoughtfully considered by PGE, the OPUC, and parties with respect to timeliness of recovery and the impact it has on customers' prices.

Finally, AWEC makes a vague reference to improved cost control, which we interpret to mean lower operating cost. Reducing operating costs can only temporarily benefit credit metrics between rate cases when those efficiencies are reflected in revenues and are generally more than offset in the interceding period by other cost pressures. PGE pursues cost efficiencies as a matter of good business practice.

Q. Does AWEC provide other misguided suggestions?

A. They do. While AWEC rightly suggests that issuance of equity, which I addressed PGE's plans previously in this testimony, AWEC also suggests that PGE should simply enter into more power purchase agreements.

Q. Why is this suggestion misguided?

A. PGE's investment grade bond ratings are determined by S&P and Moody's. Both rating agencies impute additional debt onto PGE's expected capital structure related to its obligations under long-term power purchase agreements. Increasing PGE's authorized debt ratio would further inflate its debt as a part of these calculations. Basically, PPAs look like debt to the ratings agencies which defeats AWEC's stated purpose.

Q. Is AWEC correct in stating that PGE has not provided any explanation for its failure to improve its historic equity ratio?

A. No. While we do address this matter directly in this testimony with respect to the pressure on the balance sheet from various events over the past several years there are two additional points worth considering. First, it is common for a capital structure to oscillate as debt and equity issuances tend to be large and "lumpy" causing temporary swings in the capital structure. Once adjusting PGE's financials for the leverage to support the remaining deferral balances our equity capital structure increases by 150 bps. Second, AWEC has been a party to each aforementioned deferral proceeding and is intimately familiar with the outcomes of each.

Q. Does PGE support AWEC's alternative recommendation to defer the incremental difference of the hypothetical structure relative to actuals?

A. No. Capital structure is intended to be maintained over the long term while the idea for this seems to have originated in near-term thinking as evidenced by the unidirectional example. Presumably the inverse would be true where PGE's actual capital structure to be greater than 50%, PGE would defer with an opportunity to collect from customers. Using a deferral mechanism to track the variations between actual and regulatory capital structure over the years adds unnecessary complexity to the regulatory framework and may have unintended consequences including undesirable customer price impacts and inequities.

Q. Does CUB's offer any comments on capital structure for PGE in 2025?

A. CUB comments that PGE's proposed equity ratio of 50.0% exceeds the equity ratio for the proxy group used to estimate the cost of equity. Yet, CUB also notes that PGE's request is largely in-line with what has been awarded to other electric utilities throughout the United States in recent years.[229]

Q. Does CUB propose an adjustment to PGE's 50/50 capital structure?

A. No. CUB does not propose any adjustments to PGE's capital structure.

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[229] CUB/118, Jenks/28.

V. Cost of Debt

Q. Please summarize Staff's proposed adjustment related to the cost of debt.

A. Staff's recommendation incorporates forecasted debt issuances by PGE in 2024 and 2025 based on an analysis of credit spreads, forecasted risk-free rates, and PGE's debt maturity profile. Staff recommends an overall cost of long-term debt of 4.641%, comprised of 4.548% for outstanding LT Debt and 5.746% for forecasted issuances. This differs from PGE's initial proposed 4.628%, representing an increase of 0.013% or 1.3 basis points.

Q. How do you respond to Staff's proposal?

A. PGE does not oppose Staff's change.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1801	Average of Average Equity, Regulated 2007-2023

Actual Averages										
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
LT Debt	1,110,288	1,301,025	1,575,021	1,752,643	1,770,692	1,586,400	1,666,015	1,917,650	2,047,567	2,216,942
Common Equity	1,282,882	1,343,836	1,503,232	1,567,775	1,645,560	1,700,858	1,771,352	1,870,947	2,092,557	2,293,939
LT Debt	46.4%	49.2%	51.2%	52.8%	51.8%	48.3%	48.5%	50.6%	49.5%	49.1%
Common Equity	53.6%	50.8%	48.8%	47.2%	48.2%	51.7%	51.5%	49.4%	50.5%	50.9%

Source: Results Of Operations (ROO) filings to PUC

2017	2018	2019	2020	2021	2022	2023	10YrAvg	Since 2007
2,258,455	2,226,042	2,402,892	2,626,306	2,905,856	3,214,189	3,437,290	2,525,319	2,118,545
2,386,313	2,463,126	2,544,651	2,649,594	2,768,760	2,823,501	3,092,862	2,498,625	2,105,985
48.6%	47.5%	48.6%	49.8%	51.2%	53.2%	52.64%	50.3%	50.1%
51.4%	52.5%	51.4%	50.2%	48.8%	46.8%	47.36%	49.7%	49.9%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Robert Macfarlane
Casey Manley

August 14, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Robert Macfarlane. I am a Manager, in Pricing and Tariffs at Portland General Electric Company (PGE).

My name is Casey Manley. I am a Senior Regulatory Analyst in Pricing and Tariffs at PGE.

We are responsible for the development of the marginal cost studies. Our qualifications are included in PGE Exhibit 800.

Q. What is the purpose of your testimony?

A. Our testimony responds to certain recommendations made by the Alliance of Western Energy Consumers (AWEC) regarding PGE's proposals to update the generation and customer marginal cost studies. No other party to this proceeding has provided recommendations regarding PGE's marginal cost studies. Staff of the Public Utility Commission of Oregon (Staff) reviewed PGE's model, and the rationale provided in our testimony and did not have any issues with the changes made to the studies. The Citizens' Utility Board did not propose any changes to PGE's generation marginal cost study. We outline AWECs arguments and provide a response to their proposals.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have three sections:

- Section II – Overview and Summary
- Section III – Generation Marginal Cost Study
- Section IV – Customer Marginal Cost Study

II. Overview and Summary

Q. Please provide an overview of AWEC's proposals regarding PGE's generation marginal cost study.

A. AWEC recommends the following modifications to PGE's generation marginal cost study:

1. Remove capacity value from the cost of wind and solar resources when estimating the cost of energy. Do not remove capacity value of wind and solar from battery resources.
2. Use tuned effective load carrying capacity (ELCC) under firm transmission for all resources.
3. Use local wind and solar resources when modeling the cost of energy, consistent with PGE's preferred portfolio in the 2023 Integrated Resource Plan ("IRP") and Clean Energy Plan ("CEP"). Alternatively, use Clearwater wind transmission costs for the Montana wind resource, which provides a more precise estimate of transmission costs, and 100% ELCC for the Mead solar resource.
4. Use Mid-C prices consistent with Mid-C purchases and adjust weights on wind, solar, and market energy to sum to 100%.
5. Do not remove flexibility value from battery cost because this value is appropriately included as a capacity cost.

Q. Please summarize AWECs proposals for changes to the customer marginal cost study.

A. Regarding PGE's updated customer marginal cost study, AWEC proposes updating the allocation methodology for the Flexible Load Product Portfolio and Interconnection Services departments to be spread on a 50/50 weighting of load and customer count for commercial customers rather than a spread based on load count only. AWEC did not propose any changes to the residential spread of these departments. No other Parties proposed changes to PGE's customer marginal cost study.

Q. What elements of the above proposals are acceptable to PGE?

A. PGE agrees to use the tuned ELCC value for a 4-hour battery from PGE's 2023 IRP and agrees to adjust weights on wind, solar, and market energy to sum to 100% in the Generation Marginal Cost study. PGE agrees to make AWEC's adjustment to the Customer Marginal Cost study.

Q. Please summarize any other updates to PGE's Generation Marginal Cost Study.

A. In addition to the acceptable elements of AWEC's proposals, PGE made the following updates:

1. To improve the accuracy of the model, PGE will reduce the flexibility and energy value of the 4-hour battery proportional to the capacity contribution of the wind and solar proxy resources.
2. As explained in PGE's response to AWEC DR 93, the capacity contribution of wind and solar are calculated as the 4-hour battery marginal capacity cost ($/kW-yr) in column B multiplied by the resource's ELCC multiplied by the resource's generation weighting (75% wind, 25% solar).
3. The cost year date for the battery, wind and solar proxy resources has been updated to 2023 to correct a mistake in the original model.
4. Consistent with PGE's response to AWEC Data Request 84, the cost of the Mead solar proxy resource will be calculated using the Nevada property tax rate.

Q. What actions does PGE recommend the Commission take regarding these proposals?

A. PGE recommends that the Commission reject AWEC's proposals to alter the generational marginal cost of service study except for the items deemed acceptable above and otherwise approve PGE's updates to both the generation and customer marginal cost studies as filed.

III. Generation Marginal Cost Study

A. Capacity Value of Solar and Wind Proxy Resources

Q. Does AWEC agree with PGE's method of addressing wind and solar capacity value?

A. No. AWEC claims that under PGE's model, an energy resource with high-capacity contribution will result in a negative capacity cost**.** AWEC's Confidential Table 5 is meant to illustrate this point using a hydro proxy resource with a 100% ELCC.

Q. How does PGE respond?

A. AWEC provides an unreasonable comparison. It is inappropriate to use a peaking resource to replace a variable resource in PGE's model.[1] Peaking resources have ELCCs close to 100%, whereas the ELCC values of the solar and wind proxy resources in PGE's model are 7% and 27% respectively.[2] If PGE were to replace its energy proxy with this hydro resource, then there would be no need for a battery. A hydro resource with a 100% ELCC would provide 100% of capacity and energy need, so PGE's proposed generation marginal cost study methodology would not apply.

AWEC's Confidential Table 5 does illustrate a change needed in PGE's model. The capacity contribution of the energy proxy affects the capacity needed from a 4-hour battery and should therefore affect the battery flexibility and energy values as well. As the capacity contribution of the energy proxy increases, there is less battery needed and proportionally less flexibility and energy value. This change would make the cost of capacity zero in AWEC's hypothetical above.

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[1] AWEC/200, Kaufman/7 at 1. AWEC's Figure 1 shows hydro as a peaking resource.

[2] *See* 2026-43 average tuned ELCCs for MT wind and Wasco solar in PGE's 2023 IRP, *In the Matter of Portland General Electric Company's Clean Energy Plan and Integrated Resource Plan*, LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 546-547 (Mar 31, 20123).

Q. Does AWEC make any other claims about PGE's method of addressing wind and solar capacity value?

A. Yes. AWEC claims that PGE's model is incorrect because subtracting the value of the capacity contribution of the energy proxy from the cost of capacity reduces the amount of capacity served by the model. AWEC illustrates this with the following example:

> For example, a 1 kW wind resource with 30 percent ELCC would leave 0.7 kW of capacity that needs to be served by the battery, thus the cost of the battery is scaled down from 1 kW to 0.7 kW. However, PGE fails to account for the fact that the smaller battery resource is now serving a smaller demand. As a result, PGE's model does not measure the cost of serving 1 kW of capacity, but rather the cost of serving 0.7 kW of capacity. [3]

Q. Does PGE agree?

A. No. Following AWEC's example, PGE is still modeling the cost to serve 1 kW of capacity, not 0.7 kW of capacity. A capacity value of 0.7 kW is served from the 4-hour battery and 0.3 kW of capacity is served by the energy proxy. Batteries do not generate electricity,[4] but renewable resources do contribute some capacity. In our generation marginal cost study, less battery capacity is needed because the energy proxy provides a portion of the capacity need. PGE still needs to procure the same amount of renewable energy regardless of the capacity contribution of the resource.

PGE procures battery resource to provide capacity and wind and solar resources to provide energy and environmental attributes. Renewable resources capacity contribution reduces the battery capacity needed and therefore reduces the cost of capacity. The capacity contribution of renewables does not reduce the amount of energy needed, therefore there is no reduction to the cost of energy.

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[3] AWEC/200, Kaufman /10-11.

[4] In fact, batteries lose 14% of stored energy. The ratio of useful energy output to useful energy input of a 4-hour battery is 86%. *See* LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 183 (Mar 31, 2023).

Q. What does AWEC claim is the standard method of addressing the capacity value of energy resources?

A. AWEC claims "the standard method of addressing the capacity value of energy resources is to subtract the capacity value of the energy resource from the cost of energy, not to subtract the capacity value of energy resources from the cost of capacity."[5]

AWEC's only support for this claim is that PGE used this methodology in the UE 394 Generation Marginal Cost Study that relies on a combined cycle combustion turbine (CCCT) as the "marginal long-run generation resource…used to provide both energy and capacity."[6]

Q. How does PGE respond?

A. PGE's legacy approach of isolating the CCCT's embedded capacity value from its total cost is not instructive to PGE's proposed model which improves our ability to accurately calculate the marginal cost of generation as we plan for a carbon free future. A CCCT brings both energy and capacity value to PGE's system and therefore provides a different starting point for PGE's legacy methodology. The same resource provides 100% of capacity and energy need, so for the purpose of a generation marginal cost study, its cost is divided into energy and capacity using a proxy capacity resource, the single cycle combustion turbine (SCCT).

PGE's proposed model is reflective of future resources that are non-carbon emitting. The capacity factor of the renewables determines the amount of renewables needed to produce enough electricity across the year to equal the CCCT's annual production. The ELCC of the renewables is used to determine the amount of batteries needed to serve the capacity need not provided by the renewables.

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[5] AWEC/200, Kaufman /11 at 7-9.

[6] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 394, PGE/1100, Macfarlane – Pleasant/2 at 7-19 (Jul 9, 2021).

Q. Does PGE agree with AWEC's recommendation to subtract the capacity value of wind and solar from the cost of energy instead of the cost of capacity?

A. No. PGE will continue to subtract the capacity value of renewable resources from the cost of capacity. However, PGE will fix the formulaic errors noted in AWEC Data Request 93.[7] Each renewables' capacity contribution in $/kW-year is calculated as the 4-hour battery marginal capacity cost ($/kW-yr) in column B multiplied by the ELCC of each renewable multiplied by the generation weighting of each renewable, (75% wind and 25% solar).

B. ELCC

Q. What is AWEC's argument supporting using tuned ELCC under firm transmission for all resources?

A. AWEC notes that PGE includes the cost of PGE owned transmission resources when calculating the cost of energy resources. These resources provide firm transmission. AWEC therefore claims it is not appropriate to calculate the ELCC of resources with conditional firm transmission.

Q. How does PGE respond?

A. Even though PGE includes the cost of PGE owned transmission resources when calculating the cost of energy resources, that does not eliminate the risk of conditional firm transmission. The proxy energy resources would still go over BPA's system, meaning it is still possible they would get a decrement from conditional firm transmission.

It is very difficult to procure firm transmission in the current environment. In a long-run marginal cost study it would be inappropriate to assume 100% firm transmission.

[7] Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 93).

Order No. 24-011 established Scoring and Modeling Methodology (SMM) conditions intended to lead PGE to consider more RFP bids using condition firm transmission products.[8]

Q. Does AWEC have any other concerns with the solar proxy ELCC PGE used?

A. Yes. AWEC is concerned that PGE modeled the costs of the solar proxy resource using inputs from Mead while applying the ELCC for the Wasco solar resource. AWEC argues PGE should use the Mead solar plus market access ELCC of 100%.

Q. How does PGE respond?

A. AWEC erroneously recommends combining the ELCC of a solar resource with market access. Proxy resource ELCCs should reflect the capacity contribution of the proxy resource, not of the energy market plus the resource. Forecasted market purchases are included separately in PGE's model and separately account for the contribution of market access in the calculation of the cost of energy. One can easily intuit that it would be impossible for any solar resource to supply 100% of PGE's capacity need.

Furthermore, AWEC contradicts their recommendation to use tuned ELCCs because the Mead plus market access ELCC is not a tuned value. PGE uses the Wasco solar tuned ELCC because there is no tuned Mead solar ELCC in the IRP and the Wasco value is a reasonable substitution. Overall, the solar ELCC value only has a 1.6% impact on the net marginal capacity cost, so an incremental change in its value will have a minor impact. PGE is willing to consider using the 9% firm transmission tuned Wasco solar ELCC as suggested by AWEC in their alternate scenario.

[8] *In the Matter of Portland General Electric Company 2023 All-Source Request for Proposals*, Docket UM 2274, Order No. 24-011 at 1-3 (Jan 12, 2024).

Q. Does PGE agree to use the tuned ELCC value for the battery proxy resource?

A. Yes. PGE will use the 2026-43 average tuned ELCC for a 4-hour battery.[9]

C. Energy Proxy Resources

Q. Describe AWEC's arguments regarding PGE's energy proxy resources?

A. AWEC recommends PGE use local wind and solar resources when modeling the cost of energy. Alternatively, AWEC recommends PGE use a different transmission value for the wind proxy resource and a different ELCC value for the solar proxy resource.

Q. Why did PGE select Montana wind and Nevada solar?

A. PGE selected Montana wind and Mead solar because they offer high capacity factors and diverse seasonal output compared to PGE's current resource portfolio. Higher capacity factors mean greater energy benefits, and less correlation with existing resources boosts capacity benefits. Furthermore, additional transmission options are needed to maintain reliability while meeting future load growth and emissions targets. This is a 20 year long-run marginal cost study, which underlines the need to include diverse proxy resources and additional transmission.

Q. What are AWEC's arguments supporting using Clearwater wind transmission costs for the Montana wind resource?

A. PGE assumes Montana wind transmission cost of 20.46 per kW-month. However, this is the cost of transmission to Wyoming. AWEC claims the Clearwater transmission cost is 6.86 per kW-month.

[9] *See* LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 547 (Mar 31, 2023).

Q. Does PGE agree to use the Clearwater transmission value proposed by AWEC?

A. No. It is inappropriate to use the Clearwater transmission cost to model the cost of a new wind resource as AWEC suggests because there is no additional transmission currently available. The PGE wind transmission cost of 20.46 per kW-month is reasonable cost for hypothetical extra-regional transmission.

D. Mid-C Prices and Purchases

Q. Does PGE agree to adjust weights on wind, solar, and market energy to sum to 100 percent?

A. Yes.

Q. Does AWEC make any other recommendations?

A. Yes. AWEC recommends PGE use the flat Mid-C price forecast from PGE's Intermediary GHG model.

Q. How does AWEC support their recommendation?

A. AWEC claims that the total market purchases determined in the GHG model are a function of the forecasted prices and that changing forecasted prices would change the forecasted market purchases.

Q. How does PGE respond?

A. AWEC erroneously claims that market purchases in the in the GHG model are a function of the forecasted prices. Changing the market prices in this model has no impact on market purchases[10]. Market purchases in the in the GHG model are only based on historical purchases.

[10] Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 82).

Q. Does AWEC make any other arguments to support their recommendation?

A. AWEC argues that the Mid-C price shaped by loss of load probability reflects the cost of serving capacity needs, not energy needs.

Q. How does PGE respond?

A. Loss of load shaping reflects the price of market energy when energy purchases are needed, not an unweighted annual average price as AWEC recommends. PGE's methodology is a more accurate estimation of the cost of market purchases.

Q. Does PGE agree to use the flat Mid-C price forecast from PGE's Intermediary GHG model?

A. No. As described above PGE believes its methodology reflecting the price of market energy when energy purchases are made is more accurate.

E. Flexibility Value of Storage

Q. What are AWEC's arguments supporting PGE to not remove flexibility value from battery cost?

A. AWEC argues flexibility is appropriately included in capacity cost because flexibility is fundamentally intertwined with peak needs.

Q. How does PGE respond?

A. The flexibility value should be excluded from the cost of capacity in part because "capacity need is significantly higher than the flexibility need, flexibility need is not considered a driver of resource additions within current IRP modeling."[11] Furthermore, flexibility value "represents a benefit value stream that fast-acting dispatchable resources such as batteries and certain DERs should receive for addressing flexibility adequacy", not capacity need.[12]

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[11] *See* LC 80, PGE's 2023 Integrated Resource Plan Addendum: Portfolio Analysis Refresh at 3 (June 30, 2023).
[12] *See* LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 128 (Mar 31, 2023).

PGE worked with Blue Marble Analytics to study system flexibility needs. This study found that the difference in flexibility value between storage resources does not appear to be significantly impacted by duration, suggesting that most flexibility value is associated with flexibility constraints on short time scales. [13]

Q. What is the updated fully allocated cost of each proxy resource?

A. The net generation marginal cost of capacity is estimated at $229.70 per kW-yr in real levelized 2025 dollars. The net generation marginal cost of energy is estimated at $104.71 per MWh in real levelized 2025 dollars.

[13] *See* LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 237 (March 31, 2023).

IV. Customer Marginal Cost Study

Q. Please describe proposals put forward by Parties in response to the customer marginal cost study filed in PGE's opening testimony.

A. AWEC proposed an update to one allocator that is used for both the Interconnection Services Department and the Flexible Load Product Portfolio Department. The proposed update suggests modifying PGE's allocator from 65% residential, 35% non-residential spread by load, excluding lighting to 65% residential, 35% non-residential weighted based on 50% of load, 50% of customer counts[14]. AWEC also makes a proposal regarding the budget for the Key Customer Management Department[15], which is allocated via the customer marginal cost study, but as this is a budget-related issue it is addressed in PGE Exhibit 1500.

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

A. Upon consideration of AWEC's proposal, PGE finds that it is reasonable. While load does increase the complexity, and therefore the time spent enrolling customers in the programs covered by these departments, it is reasonable to assume that once enrolled that the ongoing management of engagements with customers is reasonably related to the size.

Q. Did any other party propose changes or updates to PGE's Customer Marginal Cost Study?

A. No other parties proposed changes to the Customer Marginal Cost Study. Commission Staff stated that they found the changes to be generally sound.[16]

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[14] AWEC/200, Kaufman/25.
[15] *Id.* 26
[16] Staff/900, Stevens/10-1.

Q. Does PGE make any additional updates to the Customer Marginal Cost Study?

A. PGE makes one additional update to the allocators associated with the Interconnection Services Department to exclude Schedule 90. This was outlined in our proposal in PGE Exhibit 800[17], but was inadvertently excluded from the calculation in the workpapers.

Q. What is the impact of updating the allocators for the Interconnection Services Department?

A. This adjustment is limited to the "Other Consumer Costs" category. All other Customer Marginal Cost categories, such as billing and metering remain unchanged. Table 1 shows the impact to the allocations by rate schedule for other consumer costs.

Table 1
Impact of Changes to Other Consumer Costs Allocator

Rate Schedule	Original Proposal	Updated	Difference
Schedule 7	$37.16	$37.20	$0.04
Schedule 15 Residential	$0.83	$0.83	$0.00
Schedule 15 Commercial	$0.83	$0.83	$0.00
Schedule 32	$72.73	$76.90	$4.17
Schedule 38	$453.23	$455.24	$2.01
Schedule 47	$81.49	$85.93	$4.44
Schedule 49	$422.68	$425.69	$3.01
Schedule 83	$651.31	$646.86	($4.45)
Schedule 85	$2,380.21	$2,310.50	($69.71)
Schedule 89	$17,382.70	$15,324.15	($2,058.55)
Schedule 90	$80,922.59	$55,098.93	($25,823.66)
Schedule 91 & 95	$0.83	$0.83	$0.00
Schedule 92	$0.83	$0.83	$0.00

Q. Does this conclude your testimony?

A. Yes.

[17] PGE/800, Macfarlane-Manley/13.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Pricing and Tariff

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Robert Macfarlane
Christopher Pleasant

August 14, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Robert Macfarlane. I am the Manager of Pricing and Tariffs for PGE. My qualifications were previously provided in PGE Exhibit 800.

My name is Christopher Pleasant. I am a Senior Regulatory Analyst in Pricing and Tariffs for PGE. My qualifications were previously provided in PGE Exhibit 900.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues and proposed adjustments raised by the Staff of the Public Utility Commission of Oregon (Staff), the Citizens' Utility Board of Oregon (CUB), the Alliance of Western Energy Consumers (AWEC), Verde, Charge Point (Charge Point) and Walmart Inc. (Walmart) (collectively, Parties).

Q. How is the remainder of your testimony organized?

A. After this introduction, we have seven sections:

- Section II – Overview and Summary
- Section III – Residential Basic Charge
- Section IV – Commercial Time of Use
- Section V – Load Following Credit
- Section VI – Rate Spread
- Section VII – Net Variable Power Cost Pricing
- Section VIII – Transportation Electrification Line Extension Allowance

II. Overview and Summary

Q. Please summarize Parties' overall response to PGE's proposed Pricing.

A. Parties generally support PGE's proposals related to pricing and tariffs as filed in this rate review. Staff in their opening testimony discussed how they reviewed PGE's 2025 load forecast and did not have any modifications. Staff supports PGE's proposal to increase the Basic Charge for commercial rate schedules. Staff also supports PGE's proposed updated prices for Schedule 300 Rules and Regulations and Miscellaneous Charges. This includes updated pricing for Commercial Line Extension Allowances, Temporary Service, Meter Test Charge, Field Visit Charge, and Special Meter Reading Charge. While Staff indicates they do not support PGE's proposed update to the Load Following Credit, Staff does not offer an alternative proposal.

Parties did recommend modifications to four items of PGE's proposed pricing updates.

- Staff and CUB recommend the residential Basic Charge remain at the current price of $12 for Single Family and $10 for Multi-Family instead of the $2 increases PGE proposes.
- Staff and Walmart provided feedback on PGE's proposal to introduce a mid-peak window for Commercial Time-of-Use (TOU) schedules. Staff recommends using the historical Mid-C prices from 2022 and 2023 to calculate the proposed price differential for the on-, and mid-peak volumetric rates for the four proposed schedules. Staff also recommended PGE apply a more refined TOU rate to Schedule 90. Walmart provided feedback on the proposed TOU time periods and recommended aligning the peak demand period with the proposed on-peak period.

- Staff and AWEC provide feedback on PGE's proposed Rate Spread and the use of the Customer Impact Offset (CIO).
- Lastly, Staff discussed their analysis of PGE's proposed Transportation Electrification Line Extension Allowance and requested changes PGE should make for Staff to support PGE's proposal.

Q. Please summarize your response to Parties' positions and provide an overview of the organization of your testimony.

A. We appreciate Parties' thorough review of our Pricing proposals. Each of the areas we noted where Parties make a recommendation we address as its own section in our reply.

To summarize our positions:

- Section III addresses the topic of the residential Basic Charge, providing additional information that supports our proposal to increase the residential Basic Charge and responds to concerns expressed around bill impacts for low-income customers.
- Section IV addresses Commercial Time-of Use recommendations. PGE agrees with Walmart's recommendation to align the Saturday period with Sunday which simplifies the tariff for customers.
- Section V discusses the importance of why PGE is updating the Load Following Credit price in this rate review which has not been updated since 2018.
- Section VI responds to Staff and AWEC's proposals regarding PGE's proposed Rate Spread. Specifically, the use of the Customer Impact Offset (CIO).
- Section VII discusses PGE's proposal to remove Net Variable Power Costs (NVPC) from base energy prices in years we have a rate review filing and include them in Schedule 125 Automatic Update Tariff (AUT).

- Section VIII addresses Staff's proposed modifications to our Transportation Electrification Line Extension Allowance proposal.

III. Residential Basic Charge

Q. Please summarize Staff's and CUB's response to PGE's proposal to increase the residential Basic Charge by $2.

A. Staff and CUB do not support PGE's proposal to increase the residential charge due primarily to their concerns around bill impacts, specifically for low-income low-use customers, and the frequency of recent increases to the residential Basic Charge. Staff and CUB argue that another increase is not consistent with principles of gradualism. Staff contends that PGE's embedded Basic Charge calculation of roughly $30 should be considered an upper bound because it does not represent only short-run customer costs.

CUB challenges PGE's justification for increasing the residential Basic Charge that recovers 9% of a customer's bill. CUB is also recommending that PGE conduct more analysis on the impacts to low-income customers by utilizing the Energy Burden Assessment (EBA).[1]

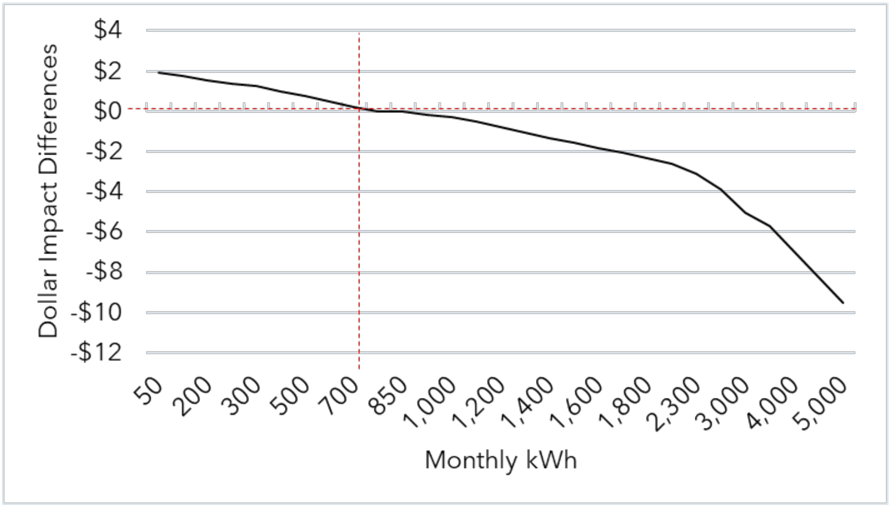
Q. Please respond to Staff and CUB's concerns on the affordability impacts of the Basic Charge for low-income customers.

A. As noted in Staff's testimony,[2] PGE's proposed $2 increase to the residential Basic Charge allows for a 0.25 cent/kWh decrease to the proposed distribution charge. The impact of these adjustments is that customers using more than the average monthly amount (~800 kWh) will have lower bills than they would without an increase to the Basic Charge. This can be especially helpful during high usage months, which a larger portion of customers use more than the monthly average kWh. Figure 1 shows the distribution of differences in monthly bill impacts as they relate to usage.[3] A positive difference indicates a higher bill with the proposed

[1] CUB/300, Wochele-Jenks/7 at 1-5.
[2] Staff/900, Stevens/16 at 8-14.
[3] See workpaper titled *2025 Bill Comp for Basic Charge Incr.xlsx* for data underlying Figure 1.

Basic Charge increase; a negative difference indicates a lower bill with the proposed Basic Charge increase.

Figure 1
Difference in Monthly Bill Impacts, by Usage



Q. If PGE increases the Basic Charge by $2 what would be the effect on customers?

A. The majority of customers would experience minimal differences in their 2025 bills as a result of PGE's proposed increase to the Basic Charge. Using customer-level data from PGE's recently completed 2024 Energy Burden Assessment (EBA),[4] over 90% of residential customers have average monthly usage of less than 1,600 kWh and would be expected to see overall bill impacts that differ by +/- $2. A minority of customers would see bill decreases in excess of $2 as a result of the Basic Charge adjustment.

Q. What are the expected impacts to customers considered low income or high burdened?

A. Among the 190,000 customers assumed to be low income,[5] nearly 60% are estimated to have lower bills during winter months (November-March) because their typical winter usage is above the residential average. This percentage falls below half for summer and shoulder

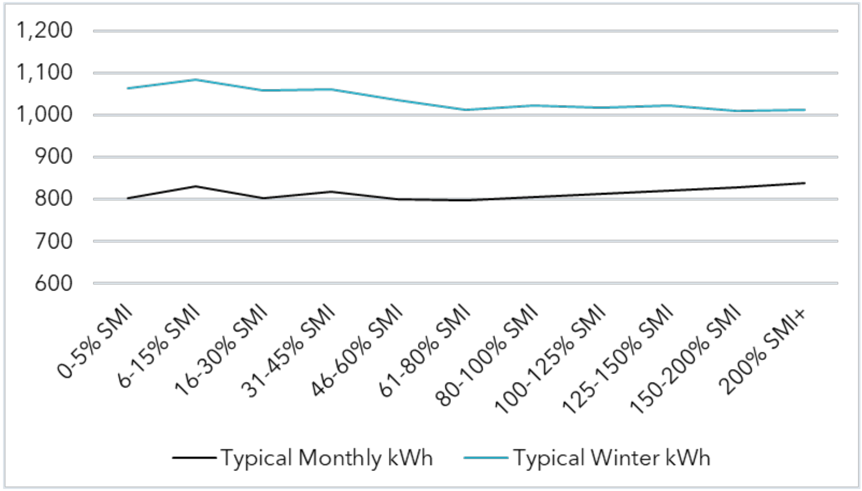
[4] Filed with the Public Utility Commission of Oregon in UE 416 and UM 2211, *In the Matter of Portland General Electric Company Request for a General Rate Revision*, PGE's Energy Burden Assessment (Jun 28, 2024).
[5] Household income below 60% of the State Median Income, adjusted for household size.

months. Among approximately 118,000 low-income customers considered to be energy burdened,[6] 60% are estimated to have lower monthly bills, on average, as a result of PGE's proposal. Over 70% are likely to see lower winter bills. The most comprehensive benefit, however, is among energy burdened customers who do not meet the definition of "low-income." All customers in this subgroup would see a decrease to their typical monthly bills and their typical winter bills. Over 90% would also see a decrease to their summer bills. Approximately 75% of these 23,000 customers have household incomes between 61-100% of state median income.

In Figure 2 we show that while typical monthly usage is fairly constant across income bands (relative to state median income), typical winter usage is inversely related to income.[7] A similar trend was found in PGE's reply testimony in Docket UE 416, when comparing winter usage among IQBD participants and non-participants.[8] The correlations between income and winter usage are generally understood to reflect that lower income households are more likely to have electric resistance heating or other inefficient HVAC systems and under-weatherized homes.

[6] Spending more than 6% of household income on electricity if home has primary electric heating; spending more than 4% of household income on electricity if home has primary non-electric heating.
[7] See workpaper titled *Usage by SMI Bands.xlsx* for data underlying Figure 2.
[8] UE 416, PGE/1300, Macfarlane- Pleasant/16, Figure 1.

Figure 2
Average Monthly Usage, by Income Band



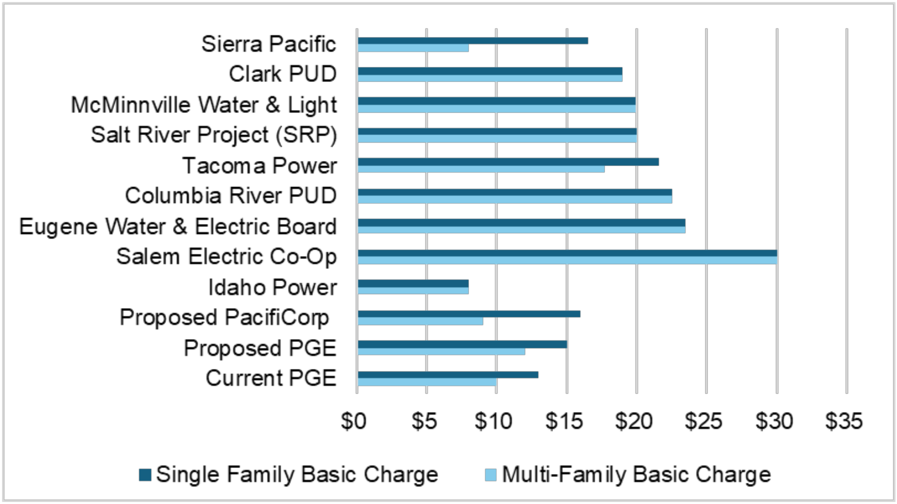
Q. Staff and CUB also raise a concern that an increase in the Basic Charge is not in line with gradualism principles. How do you respond?

A. We disagree with this assertion. It is important to proportionately allocate residential increases to both the volumetric charges and the fixed Basic Charge so long as the Basic Charge remains below the calculated embedded value. This aligns with gradualism principles. Not only does this allow PGE to reasonably maintain proportional recovery of fixed costs with a fixed charge; an increase to the Basic Charge is offset with a decrease to the per kWh distribution charge which can benefit customers. Specifically, a lower volumetric charge helps protect customers, low income and not, from more extreme bills in the face of high usage periods during more extreme seasonal temperatures and weather events.

Q. How does PGE's proposed Basic Charge compare to other utilities in the West?

A. PGE's proposed Basic Charge of $15 for Single Family and $12 for Multi-Family customers is similar to that proposed by PacifiCorp in UE 433, $16 for Single Family and $9 for Multi Family, and well below the residential fixed charges of public utilities in the region. Figure 3 shows illustrates the comparison of Basic Charges for 10 regional utilities.

Figure 3
Comparison of Residential Customer Charges Among Utilities in the Northwest

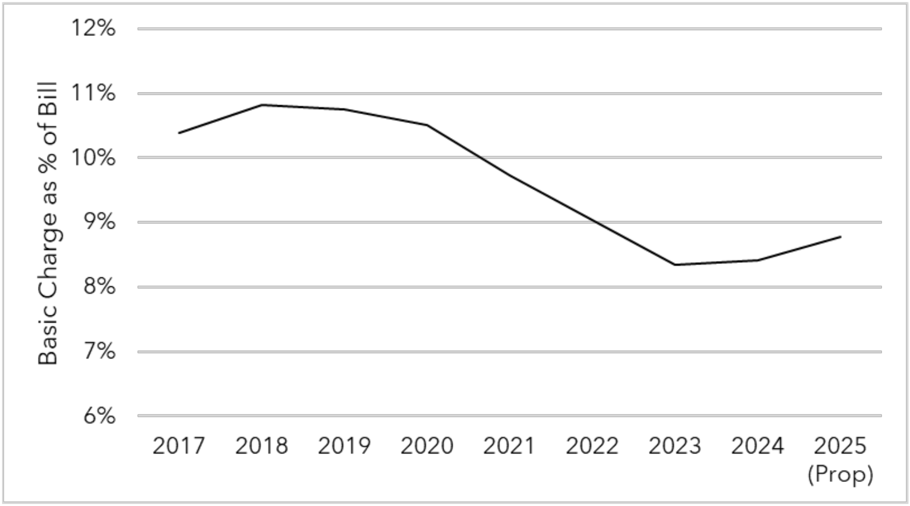


Q. Another argument raised by CUB was that an increase in the Basic Charge is not justified based on prior rate review settlements.

A. In response to CUB's point that UE 394 settled on specific dollar amounts for Single Family and Multi-Family Basic Charges and not a particular percent of bill, PGE acknowledges that 9% is not a precise target on which to anchor the relationship between the Single Family Basic Charge and the typical residential bill. Rather, we assert that when bifurcating the Basic Charge in UE 394 to appropriately reflect the lower fixed costs associated with serving more densely located Multi-Family units, PGE accepted a decrease in fixed revenues from residential customers, exposing customers to higher bills during extreme temperatures and exposing the Company increased revenue fluctuations. Figure 4 illustrates the declining impact of the residential Basic Charge in recent years, down from 11% in 2018 to nearly 8% in 2023 and 2024. [9]

[9] See workpaper titled *Basic Charge by Year.xlsx* for data underlying Figure 4.

Figure 4
Proportion of Typical Residential Bill Allocated to the Basic Charge



Q. How do you respond to Staff's contention that the embedded Basic Charge indicated by PGE's marginal cost study should be considered an upper bound?

A. PGE does not consider our embedded Basic Charge calculation to be an upper bound. It represents the actual fixed costs to serve residential customers and includes costs from the following cost categories: Meters, Transformers & Service, Uncollectibles, Metering-Customer Service, Billing and Other Consumer-Customer Service. Removing transformer costs from PGE's marginal cost categories, in any event, supports an embedded residential Basic Charge of $16 for the residential class overall. This is still higher than PGE proposed $15 for Single Family customers and $12 for Multi-Family customers. Specifically, Staff asserts that transformers and "longer-term programmatic costs"[10] should be removed because they reflect longer time horizons than the other cost categories. PGE disagrees with this approach. The majority of new residential connects are often new construction subdivision additions, adding dozens or hundreds of new home or apartment units at one time, requiring a transformer rather than single home builds in an existing neighborhood where the

[10] Staff/900, Stevens/19 at 11-16.

transformer is already there. As such, transformer costs should be included in the marginal cost of adding a residential customer.

IV. Commercial Time of Use

Q. Please summarize Staff's response to PGE's Commercial Time of Use (TOU) Proposal.

A. Staff is supportive of PGE's proposal to add a mid-peak window to Schedules 38, 83, 85 and 89. Staff reviewed PGE's proposed commercial TOU hours and found the on-, mid- and off-peak windows align with the findings of our most recent Loss Of Load Probability (LOLP) assessment. Staff did, however, have concerns with the proposed price differential for the on-, and mid-peak volumetric rates for each of the four schedules. Staff is recommending that the TOU rates for Schedules 38, 83, 85, and 89 use the historical Mid-C prices from 2022 and 2023. Staff is making this recommendation on its assumption that "a wider spread between the on-peak and mid-peak rate may provide a stronger incentive for customers to shift their load from the highest-cost and highest congestion hours than the rates currently proposed by the Company."[11]

Staff also recommends that PGE apply a more refined TOU rate to Schedule 90. Staff provides the following three reasons:

1) Schedule 90 customers may be able to shift load regardless of their relatively flat load profile,
2) A refined TOU structure would better align costs with prices, and
3) A new TOU proposal for Schedule 90 would be revenue-neutral to PGE and cost-neutral to the presumed single customer on the schedule.

[11] Staff/1700, Dlouhy/46 at 1-4.

Q. How does PGE respond to Staff's recommendation to use the historical Mid-C prices from 2022 and 2023 to calculate TOU rates for Schedules 38, 83, 85 and 89?

A. PGE is open to this recommendation and will adjust the allocations to TOU periods based on historical Mid-C prices instead of forward curves. However, PGE recommends a 3-year historical window to further smooth over any annual anomalies. This shift results in a larger spread between on-peak and mid-peak prices and a smaller spread between mid-peak and off-peak prices. It does not, however, widen the overall differential between on-peak and off-peak prices. PGE has intentionally bound the overall spread in order to prevent rate shock at the onset of this structural adjustment to energy pricing and will consider further methodological adjustments in the future.

Q. How does PGE respond to Staff's recommendation that a non-residential TOU rate should also be applied to Schedule 90 customers?

A. Continuing to use the two-period NERC heavy load and light load hours for Schedule 90 energy charges remains appropriate for several reasons. First, Schedule 90 is for PGE customers with the largest and most constant load. Customers on Schedule 90 typically have monthly load factors in the 90-100% range. These are customers in the business of manufacturing computer chips or large data centers. These loads tend to stay constant as computer chip manufacturers have less flexibility to shift load or move their energy consumption to a different time interval because computer chip manufacturing is a multi-day and, in some cases, a multi-month assembly line process to produce their product.

Secondly, the current Schedule 90 rate already aligns its costs with the rate they are charged. Since PGE's Schedule 90 customers have a load shape, that is relatively constant, PGE can plan for these customers' load in our long-term power planning. PGE does not incur higher costs to serve this load in high-demand periods because the actual load is unlikely to exceed the forecast.

Last, adding a mid-peak window to Schedule 90, as Staff points out in testimony, "will be revenue neutral to the Company and cost neutral to Schedule 90…Therefore, if the single [sic] customer does nothing to respond to the new price signal created by TOU rates, the customer should expect no change to its overall bills across its site."[12] This assumption would be have been true up to the end of 2023, but as of January 2024, a second customer now takes service on Schedule 90, so it is likely that the two customers would have varying bill impacts from the introduction of a mid-peak window, even if designed to be revenue neutral for the schedule.

Q. Please summarize Walmart's response to PGE's Commercial TOU Proposal.

A. Walmart also did not have significant concerns with PGE's Commercial TOU proposal to add a mid-peak window but did offer two specific recommendations. Walmart is concerned with PGE's proposal to segregate Saturday into its own separate period which would require customers to manage usage differently on Saturdays than they would for Monday through Friday. Walmart recommends PGE align the Saturday period with either the Sunday or Monday through Friday Periods.

Walmart's second concern is around the misalignment between the energy and demand peak period. To clarify, PGE's proposal does not include an adjustment to the hours in which peak demand is assessed. Rather, the peak demand charge is based on the highest demand that occurs in either the on- or mid-peak periods. Walmart recommends however, that the period

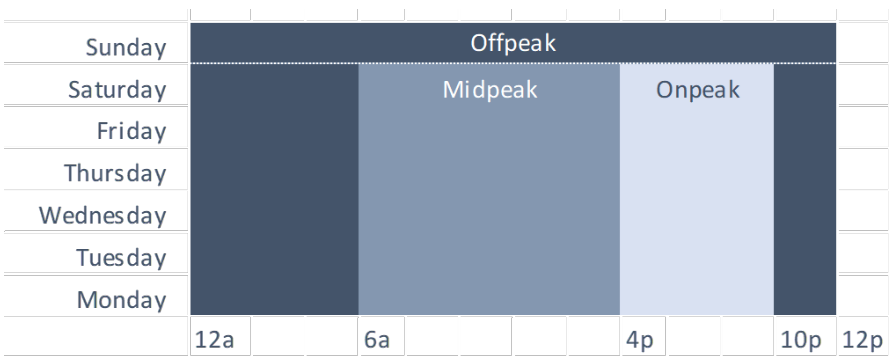
[12] Staff /1700, Dlouhy 47 at 18-19 and 48 at 1-3.

used for determining the peak demand charge align with the proposed periods used for calculating the on-peak energy charge.

Q. Does PGE agree with Walmart's recommendation to align the Saturday period with either the Sunday or Monday through Friday periods?

A. Yes. PGE sees value in aligning the on-peak, mid-peak, and off-peak periods on Saturday with the Monday through Friday time periods. We agree with Walmart's request for two unique structures while also maintaining PGE's guidance that the on-peak and mid-peak windows, when combined, align with the current 6 a.m. to 10 p.m. on-peak window to simply migration between cost of service and direct access schedules. Figure 5 illustrates this revised proposal.

Figure 5
Revised Proposal for TOU Periods – Schedules 38, 83, 85 & 89



Q. How does PGE respond to Walmart's recommendation that the time used for determining peak demand align with the proposed on-peak energy window?

A. PGE understands Walmart's recommendation but does not propose modifications to the current peak demand hours of 6:00 a.m. to 10:00 p.m. Monday through Saturday at this time. Customers on Schedules 83 and 85 are assessed unique demand charges that recover generation, distribution, and transmission costs separately. We intentionally do not want to introduce differing peak demand periods by contracting the generation demand window to

4 p.m. to 10 p.m. because it adds significant complexity to the rate design for affected customers and to PGE's implementation of the proposal.

We also do not recommend shortening all peak demand periods to align with the on-peak energy period, as an alternative approach to meeting Walmart's recommendation, because that would be a significant structural change to large commercial and industrial customer pricing. PGE's current TOU proposal is limited only to Cost-of Service rate schedules since they receive their energy from PGE. Introducing a comprehensive peak demand period that applies to all demand-related charges would require PGE to expand our TOU proposal to Direct Access schedules as well. Customers on Direct Access are billed demand-related charges for transmission and distribution costs and receive a separate bill for their volumetric energy from the Energy Service Supplier. Expanding PGE's TOU proposal to all demand-related charges requires further analysis and planning for system implementation. PGE will continue to assess the structure of demand charges and associated peak periods.

V. Load Following Credit

Q. Please summarize Staff's response to PGE's proposal to update the Load Following Credit.

A. Staff indicates they are still investigating the Load Following Credit and initially recommends that the Load Following Credit remain unchanged from the current amount. Staff does not support PGE's proposed update to the Load Following Credit because they do not agree that the value provided by Schedule 90's load profile is equivalent to 100% of the flexibility value of a four-hour battery.

Q. Does PGE agree with Staff's rationale regarding the update to the Load Following Credit?

A. It is imperative to update the Load Following Credit in this proceeding. As we mentioned in our Opening Testimony the load following integration/credit was last updated in PGE's 2018 GRC, in Docket UE 319. The current price is based on outdated inputs from PGE's 2016 IRP. For example, the flexibility value is based on a natural gas plant which is no longer appropriate. With the passage of House Bill 2021 which requires that utilities have Clean Energy Plans and be carbon free by 2040, it is appropriate to update the load following/integration credit price based on the flexibility value of a four-hour battery. Just as Staff would not want PGE to use carbon emitting resources in its generation marginal cost studies, they should not advocate to use carbon emitting resources to value flexibility. In addition, the inputs for the existing flexibility values are outdated and no longer applicable.

Q. What is the rationale for the Load Following Credit for Schedule 90?

A. To receive the load-following credit a customer must meet the following conditions, the customer must have aggregate energy usage above 250 MWa and maintain a load factor of

80% or greater for each account. The benefits of volume and load factor are significant for the remainder of PGE's customer base. Due to the consistent nature of Schedule 90's load, the customer's load is always consistent, PGE does not need to operate a Peaker plant or buy energy in the short-term market to serve this customer's load. The load-following credit recognizes this benefit.

VI. Rate Spread

Q. What is the rationale behind PGE's proposed Rate spread?

A. PGE did not introduce any new rate spread changes in this case. As we have done in previous rate cases, we set the Transmission Related Service Charges and Distribution Demand Charges by combining the transmission-related costs and billing determinants and the distribution-related costs and billing determines for Schedules 83, 85, 89 and 90 such that these schedules will have the same secondary voltage and primary voltage demand charges. In general terms the Transmission Related Service Charge and Distribution Demand Charge prices are thus equalized and result in the same price regardless of schedule. To ensure Schedule 15 Outdoor Area Lighting, Schedules 91/95 Street and Highway Lighting and Schedule 92 Traffic Signal Lighting all have the same Flat Energy Price PGE uses a CIO between these lighting schedules to equalize the energy price. This approach is consistent with previous rate spread practice.

Q. Did PGE utilize the CIO for any other rate schedules to limit the amount of the proposed rate increase?

A. Yes, PGE limited the increases for Schedules 38, 47 and 49 to 1.5 times the proposed overall average price increase (excluding LIA and PPC) by allocating the increases to the lowest impact schedule, which is Schedule 90. The total dollars reallocated to Schedule 90 from this use of the CIO was approximately $983 thousand.[13]

[13] See PGE/900, Macfarlane-Pleasant/36 at 4-16.

Q. Please summarize Staff's feedback on PGE's proposed Rate spread.

A. For schedules 38, Schedule 47, Schedule 49, Schedule 89, Schedule 91, and Schedule 92 Staff recommends a cap on the average percent increase of 125 percent and a floor of 89.4. Staff's proposal is revenue neutral.

Q. How does PGE respond to Staff's proposal to cap the overall price increase at 125 percent and impose a floor of 89.4 percent?

A. We find Staff's proposed bands to be too narrow and do not see how this proposal could align with Staff/200 which recommends limiting the residential impact to three percent or less.[14] PGE sought clarification from Staff on how the rate cap proposal would work with Staff's recommendation to limit the residential impact to three percent or less, unfortunately Staff's response failed to provide clarity and was not supported with any work papers, see PGE Exhibit 2001. It is also hard to evaluate Staff's proposal at this juncture in the proceeding because the revenue requirement, marginal costs study and rate design proposals are all subject to change and thus the proposed caps and floors could also change. [15] There does not seem to be a basis for these limits.

Q. Did any Party take issue with respect to the CIO proposed in PGE's rate spread?

A. Yes. AWEC disagreed with PGE's use of the Customer Impact Offset (CIO) to equalize distribution charges for PGE's lighting Schedules (Schedules 15, 91 and 95). AWEC prefers this outcome is achieved through rate design rather than the CIO or rate spread[16]

[14] Staff/200, Scala/6 at 13-15.
[15] Staff/900, Stevens/14 at 2-3.
[16] AWEC/200, Kaufman/29 at 7-8.

Q. How does PGE respond to AWEC's issue with PGE's rate spread?

A. AWEC may be under the assumption that PGE equalizes the distribution charges for PGE's lighting Schedules 15, 91, and 95 by shifting revenue requirement away from these schedules and towards Schedule 90 through the CIO. This is not the case. The CIO is not moving dollars between the lighting schedules and Schedule 90.

VII. Net Variable Power Cost Pricing

Q. In what base rate or Schedule does PGE recover Net Variable Power Costs (NVPC)?

A. PGE currently includes NVPC in our base rate energy prices in years with a rate review. In non-rate review years, the incremental change to NVPC is recovered in a separate schedule, Schedule 125 Annual Power Cost Update (AUT). Currently, Schedule 125 prices are set to zero for 2024 because PGE's NVPC for 2024 are included in base energy prices.

Q. Has PGE received feedback from Stakeholders regarding how NVPC are priced from year to year or in rate reviews?

A. Over the last couple of years PGE has received many questions from Staff and Stakeholders via data requests and informally asking PGE to provide specific details on how much of a rate review rate change is driven by changes to NVPC's. Additionally, CUB highlighted in its testimony difficulty customers had understanding the January 1, 2024, price change impact, as NVPCs, were a significant driver of the rate impact, and were incorporated into base rate changes and not otherwise shown in isolation in Schedule 125.

Q. What does PGE propose to help improve clarity between the base rate and annual NVPC price changes attributed to Schedule 125?

A. PGE proposes to include NVPCs in PGE's Schedule 125 tariff year to year rather than including NVPCs in our base rate energy prices during years with a rate review. This will better isolate and communicate on customer bills the price impacts related to base rates and NVPCs going forward. This is also similar to PacifiCorp and their Schedule 206 Power Cost Adjustment Mechanism tariff. PGE Exhibit 2001 provides a redline of Schedule 125 with PGE's proposed changes.

Q. What is the impact of this change?

A. There is no impact to the customer. The intent is to simply more clearly demonstrate as-needed base price changes from annual NVPC Schedule 125 price changes on customer bills. This in part, responds to some of the concerns raised by CUB, with additional focus on bill improvements discussed further in PGE Exhibit 1200.

VIII. Transportation Electrification Line Extension Allowance

Q. Please summarize Staff's testimony regarding the Transportation Electrification Line Extension Allowance (TLEA).

A. Staff analyzed PGE's TLEA and disagreed with a few assumptions made in the cost benefit analysis presented in PGE's Opening Testimony. Staff states the PGE should have used an avoided generation capacity of $228 per-kW-year instead of the $144 per-kW-year value used and that the average hourly power costs used were "unreasonably low."[17] Staff further states that PGE's benefit cost ratio (BCR) of between 0.97 and 1.09 is too low when compared to PacifiCorp's BCR of 1.33 for their TLEA. Staff also states that a "Schedule 38 customer eligible for the proposed TLEA receives service at a parity ratio of 0.97, meaning marginal allocated revenues are below the cost to serve."[18] Staff recommends that PGE continue to propose make-ready budgets in the TE plan or revise the TLEA calculation to account for the subsidization in Schedule 38 and raise the BCR.

Q. Does PGE agree with Staff's proposed assumptions for the cost/benefit analysis?

A. No. The $228 per-kW-year number cited from UM 1893 was the result of an inconsistency in the Effective Load Carrying Capability (ELCC) calculation that PGE clarified in that docket. The correct figure is $175 per kW-year after correcting the inconsistency and tuning the 2026 ELCC, which more appropriately reflects PGE's current preferred portfolio. The $144 per-kW-year number is consistent with what PGE currently uses in BCR models, though in light of UM 1893's progress, we are willing to update that figure to $175 per-kW-year in our model. Regarding Staff's comment about the average energy costs

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[17] Staff/1666, Bolton/5.
[18] *Id.*

used being unreasonably low compared to AURORA modeling outputs recently viewed, PGE cannot verify the price forecast used as Staff did not specify which AURORA modeling output was used. PGE used the reference price forecast from the most recent Commission-acknowledged IRP in PGE's model. These are the most appropriate as they originate from an established process. Energy prices are highly variable and can vary due to the complexity of the planning horizon. It is appropriate to use energy prices that have been acknowledged by the Commission and thoroughly vetted.

Q. What impact does updating the generation capacity credit from $144 per kW-year to $175 per kW-year have on the cost effectiveness of the TLEA?

A. Updating the generation capacity credit reduces the conservative-case BCR from 0.97 to 0.94, which is not a material impact and the conservative-case BCR remains close to 1. PGE's forecasted case remains over 1 with a value of 1.23. PGE's conservative case represents the minimum contractual commitments of a group of 22 existing fleet customers. The forecasted energy usage of these customers is based on their travel patterns and vehicles selected. Given that PGE anticipates energy utilization will land somewhere in between the conservative and forecasted cases, a conservative BCR estimate that is just under 1 is reasonable. Table 1 shows PGE's original and updated results from the BCR model.

Table 1
BCR Model

Results	Staff Conservative Case	Staff Forecasted Case	PGE Revised Conservative Case	PGE Revised Forecasted Case
BCR	0.86	1.09	0.94	1.23
Benefits – $000s	8,772	12,897	8,772	12,897
Costs $000s	10,187	11,785	9,311	10,499

The costs and benefits listed in the table are an aggregate of costs and benefits over the 25-year life of the make-ready equipment. The annual difference between the costs and benefits for the conservative case is $22,000 in total which is minimal considering the aggregated benefit calculation does not yet include future flex load benefits the required equipment enables.

Q. How does PGE respond to Staff's assertion that PGE's TLEA should have a benefit-cost ratio (BCR) equivalent to PacifiCorp's BCR of 1.33?

A. Comparing PGE's TLEA to PacifiCorp's is inappropriate. PGE and PacifiCorp's TLEAs differ in design. The analysis conducted by PacifiCorp was created using their Resource Value of Solar (RVOS) model as the foundation, while substituting TE load shape to conduct their analysis. RVOS models take costs into account on an hourly basis and look at the costs based on the shape of the load being studied in the model. This is a new approach and Staff themselves recommend that the use of RVOS not be seen as setting a precedent for its future use.[19] PGE's analysis is materially different and does not consider all costs such as Transmission and Distribution on an hourly basis. As such PacifiCorp's BCR should not be used as a benchmark for PGE's BCR because the two models are fundamentally different. Further, PacifiCorp's line extension differs from PGE's in that make-ready infrastructure is not covered by the line extension and there is no penalty to the customer for not meeting their load commitment, so the economics differ.

Q. Please summarize how Staff compared the overall Schedule 38 marginal costs to the proposed Schedule 38 revenues?

A. Staff compared only the Schedule 38 Energy Revenues compared to the Schedule 38 Marginal Energy Costs for the Schedule 38 rate class. In Staff Exhibit 1605[20] Staff performed this calculation to get a parity ratio of 0.97. Because of the parity ratio Staff calculated, they make

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[19] *PacifiCorp's Advice No. 20-009, Rule 13, Line Extension Allowance for Non-Residential Transportation Electrification Customers*, Docket ADV 1148, Staff Report at 6 (Nov 13, 2020).

[20] Staff/1605, Bolton.

the following conclusion, "this ratio indicates a Schedule 38 customer would be subsidized by other customers in two ways: a tariff energy price lower than the cost to serve the customer, and the TLEA that does not generate enough benefit to cover the costs of the program."[21]

Q. Is Staff's analysis of the marginal cost to serve Schedule 38 customers correct?

A. No. Simply using only energy revenues compared to marginal energy costs to determine if a line extension allowance is cost-effective or if a subsidy exists is not accurate. The costs of a line extension to the Company are driven by distribution costs. For example, the cost for a transformer and a service drop to serve the customer. While PGE acknowledges that energy does play a part in the analysis of the TLEA because make-ready infrastructure is covered, ignoring distribution costs and revenues renders an incomplete analysis.

Q. What Schedule 38 marginal costs should be compared to the proposed Schedule 38 revenues?

A. In Staff Data Request 369, PGE demonstrated the marginal cost to serve Schedule 38 load compared to the Basic and Distribution Charge revenue PGE receives. PGE includes in its marginal cost to serve Schedule 38 load the following marginal costs: Substation, Subtransmission, Meter, and Customer.

Q. Does this comparison indicate any subsidy by other customers to Schedule 38?

A. No.

Q. Are there benefits to providing a TLEA that are not considered by the BCR model or that are not currently quantifiable?

A. Yes, there are numerous benefits to providing a TLEA to customers that either cannot be measured or are not considered when looking only at revenues versus costs. By providing a

[21] Staff/1600, Bolton/6 at 17-20.

line extension paired with make-ready infrastructure, PGE has a higher level of engagement with fleet customers early in the design process to better plan for their energy needs on a longer time horizon than would otherwise be possible without this engagement. Early engagement with these customers means that PGE can be more planful about impacts to the grid. The TLEA also requires demand response qualified chargers to be installed, which will allow participation in future commercial EV flex load offerings. PGE has started demonstrations in the fleet managed charging space to gain technical learnings for future commercial managed charging offerings. Customers would not be able to participate in those offerings if they do not have capable chargers and there would be lower realized grid benefits for all customers due to the inability to participate in programs. It is difficult to assign a value to these benefits as they are longer term benefits that may not have a monetary value assigned today but are invaluable to the long-term health of the grid.

Q. Does ChargePoint agree with PGE's TLEA?

A. Yes. ChargePoint supports the Fleet TLEA proposal in anticipation of funding ending in the existing pilot. ChargePoint agrees that the Fleet TLEA will provide needed support for fleet customers evaluating the investment to electrify their fleet.[22]

Q. Should the Commission approve PGE's TLEA?

A. Yes, the Commission should approve PGE's TLEA. Even when using a conservative estimate, the BCR is close to 1 and with the forecasted case, the BCR is greater than 1.

If the Commission were to decide to direct PGE to offer the TLEA in its current state with expenditure requests occurring through the TE Plan, PGE requests that there be a process other than refiling the entire TE plan to more frequently review budget requests for the TLEA

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[22] ChargePoint/100, Skowron/18.

because there is a high likelihood of all funds being reserved within a three-year TE plan cycle. This creates an inconsistent experience for customers, leading to the delay of the customer's request for development of fleet infrastructure. These delays in funding cause potential customers to pause their request for service in the hopes of additional funding from additional budget being approved through the TE plan process every three years. This creates a compounding issue due to the paused projects and new projects entering the pipeline, as well as constraints on system planning and our ability to execute these projects and meet our customers' needs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2001	Staff Response to PGE Data Request 1
2002	Draft Schedule 125 Tariff

Date: August 2, 2024

TO:
Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC-0306
Portland, OR 97204

FROM: Michelle Scala, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 435 – PGE Data Request No. 1

PGE Data Request No. 1:

Please refer to Staff/200, Scala/38. Regarding Staff's recommendation of a cap on a residential increase of 3% of PGE's overall revenue requirement proposal:

a. Please clarify and provide an illustrative example of what Staff means by a cap based on overall revenue requirement and explain whether that cap applies to: all residential customers, is based on the proposed incremental revenue requirement increase, includes power costs or other known and measurable changes to annual tariffs?
b. Please explain how Staff intends the mechanics of the cap to work.
c. Please describe why Staff thinks it is appropriate for all residential customers to receive the proposed 3% cost cap?
   - Provide any analysis performed by Staff in developing this proposal.
   - Provide all research relied upon by Staff for this proposal showing where other Commissions or utilities have applied a similar cap.
   - Describe in narrative form the analysis performed by Staff of any potential financial impacts to PGE and other customer classes when developing Staff's proposed cap. Provide copies of all documentation and research used for Staff's analysis.
d. Please provide all analysis and work papers with formulae intact of the estimated cost impacts to all other customer classes from Staffs proposed 3% cap.
e. Reference Staff's Proposed Rate Spread in Table 4 of Staff 900. Please describe how Staff's proposal for a 125% cap will work with Staff's proposal in Staff/200 for a 3% cap. Provide all workpapers and analysis performed by Staff to develop the interplay of these proposals.
   - Specifically describe and show the reconciliation of the 3% cap proposal with PGE's marginal cost study and Staff's proposed rate spread in Table 4 of Staff/900.

OPUC Data Response No. 1:

Staff's recommendation (described in Exhibit Staff/200, Scala/38 and referenced in the Company's DR 1), reads "[t]he final determination of rate spread in conjunction with revenue requirement ensures that the residential class sees an increase of no more than three percent of revenue requirement.

a. Functionally, the three percent limit is intended to apply to the entire portion of the UE 435 incremental base revenue increase assigned to PGE's residential class of customers at the conclusion of this proceeding. At this time, the three percent "cap" excludes power costs and is limited to base rates. The limit is inclusive of Staff's revenue requirement adjustments provided in its filed UE 435 Opening Testimony.

   Illustratively, the three percent limit would function as an affordability threshold for the Commission to consider when evaluating the collective terms of UE 435 issues. For example, if the combined effect of the UE 435 proposal(s) before the Commission, including but not limited to rate spread, return on equity (ROE), and revenue requirement, result in an increase to residential revenues greater than the threshold, then Staff has flagged that there is a heightened risk to residential affordability and energy justice concerns. Thus, the Commission may use this context to inform how it considers the practical impacts of the general rate case on residential communities and whether further refinements on any or all of the issues are warranted to minimize human harms.

b. While Staff's three percent limit was informed by the estimated combined effect of Staff's Opening Testimony revenue requirement adjustments and rate spread cap and floor proposal, the recommendation is provided within an energy justice context to be used by the Commission as a simplified upper bound when considering the collective impacts of the case on residential affordability. Staff distinguishes that the limit is not intended as a formalized mechanism to establish a specific treatment of costs. Rather setting a threshold serves as a tool within larger and evolving affordability frameworks and policies as they relate to ratemaking principles. It should not be assumed that adopting the threshold in this case would necessarily result in excess revenue requirement being spread across nonresidential schedules. Rate spread represents just one of many levers influencing the outcomes of this proceeding. Thus, using the three percent threshold as a residential affordability reference point, benchmarked to Staff's UE 435 adjustments, is discretionary to the Commission as it makes interrelated decisions across elements of this proceeding.

c. Staff objects to this question on the basis that it is overly broad and burdensome, considering the extensive data it would necessitate providing. This is compounded by the diverse aspects of the rate case that Staff would be expected to align at this moment to achieve Staff's proposal of a three percent limit on residential impacts via rate spread and address residential affordability as a matter of policy.

Notwithstanding, as noted, the three percent value of Staff's proposed limit was largely informed by Staff's UE 435 Opening Testimony rate spread (Staff Exhibit 900) and revenue requirement adjustments (Staff Exhibit 300). While Staff did not calculate the rate spread based on all of its adjustments, Staff estimated the rate impact to residential customers by finding the overall revenue increase from its proposed adjustments and applying the residential class's ratio compared to the average increase in Staff's proposed rate spread. Staff then set the cap at roughly the level of the residential increase from this method.

That said, Staff again reiterates that this limit was provided in the context of Staff's energy justice testimony and is not principally a mechanism to necessarily restrain rate spread. Inclusion of a limiter on residential impacts was supported by Staff's review of energy insecurity and affordability metrics, including but not limited to arrearages, disconnections, and IQBD measures which revealed significant concerns around residential customers' ability to afford their monthly energy bills. This assessment was further grounded by the Company's Energy Burden Assessment findings and qualitative statements provided by PGE's residential customers in the UE 435 Public Comment period. To these ends, Staff sought to provide a threshold, informed by its Opening Testimony analysis and adjustments as a tool for the Commission to use in a holistic evaluation of the rate case as it relates to residential impacts

Staff proposes this rate increase threshold for the Commission's consideration as Staff believes that both its revenue requirement adjustments and rate spread are reasonable, but any increase above Staff's three percent limit is likely unreasonable and unduly burdensome. Staff only proposed a cap for residential customers as they have seen some of the highest rate increases in recent years and their consumption of energy is directly related to health, safety, and the facilitation of modern life. The Commission has been given explicit authority to make decisions based on affordability (ORS 757.230).

Rate spread caps have commonly been proposed and used in Oregon.[1] If the Commission chooses to apply the three percent limit as a rate spread cap, this would not be a novel proposal. If the Commission chooses to authorize the limit by maintaining a rate spread while reducing the Company's revenue requirement, this would be less precedential. Staff offers the options both to apply the cap at all and if adopted, how to administer it to the Commission and has found no evidence that the use of such a threshold should be deemed inappropriate or illegal.

[1] See Order No. 22-491.

Staff did not perform a financial analysis on the impact of the three percent limit. Hypothetically, if the limit is applied as a rate spread cap, there would be no marginal financial impact to the Company from its adoption. However, there could be a marginal financial impact to any customer classes who bore the additional portion of the revenue requirement spread as a direct result of the cap if applied exclusively in this manner. That said, if the Commission were to instead establish PGE's revenue requirement in a manner that satisfies the limit, there could be a marginal financial impact to the Company. The marginal financial impact is impossible to calculate as it would be based on the final revenue requirement after all other adjustments are made. Staff found no additional value in completing this analysis as there were too many unknowns and too many scenarios by which the Commission may choose to authorize the limiter.

d. As stated above, if Staff's adjustments are adopted by the Commission, the cap was constructed such that there would be little to no impact to the Company or other customers. The marginal impact of the cap will depend on which adjustments are adopted by the Commission and how the Commission decides to implement the cap.

e. Again, Staff's proposed three percent cap is based on Staff's proposed adjustments and rate spread. If both of these are adopted, there will be no marginal impact from the cap on other customers nor will it alter Staff's rate spread proposal in a material way. If there are slight adjustments to Staff's rate spread proposal needed to facilitate the cap, then Staff is open to consider these adjustments.

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an automatic adjustment clause as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 90, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91, and 95 are exempt from Schedule 125.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- NVPC Modeling Changes
- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Wind energy forecast based on a five-year rolling average.
- Costs associated with wind and solar integration. The battery portion of wind and solar projects that have a battery storage component may be included if the battery is charged solely by wind and solar generation.
- Dispatch of energy storage systems.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs.
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes.

DRAFT

SCHEDULE 125 (Continued)

ANNUAL UPDATES (Continued)

- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- Reciprocating engine lubrication oil costs.
- Projections of State and Federal Production Tax Credits.
- No other changes or updates will be made in the annual filings under this schedule.

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent Annual Power Cost Update, adjusted for a revenue sensitive cost factor of 1.0346.

FILING AND EFFECTIVE DATE

Should the Company propose modeling changes outside of a general rate case to be effective on January 1st of the following calendar year, the Company will file estimates of the proposed modeling changes and all associated minimum filing requirements no later than February 15 of the calendar year prior to the rate effective date. Any estimates for modeling changes proposed in a general rate case year shall be filed at the earlier of either the filing of GRC opening testimony or by April 1st prior to the rate effective date.

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On or before November 6th or the next available business day if the 6th is on a weekend of each calendar year, the Company will file estimates with the final planned maintenance outages from the October 1st filing, load forecasts from the October 1st filings, load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, new market power and fuel contracts entered into since the previous updates, and updated projections of gas and electric prices, power, and fuel contracts.

DRAFT

SCHEDULE 125 (Continued)

FILING AND EFFECTIVE DATE (Continued)

On November 15th, or the next available business day if the 15th is on a weekend the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) the final planned maintenance outages and load forecast from the October 1st filing, 3) final update to Qualifying Facilities online dates, and 4) final price for the energy generation at the Priest Rapids and Wanapum hydro facilities, as provided in the power contract between PGE and Grant County.

RATE ADJUSTMENT
The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent Annual Power Cost Update applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent Annual Power Cost Update s.

ADJUSTMENT RATES

Schedule		¢ per kWh
7		5.093
15		3.714
32		4.526
38	On-Peak Period	5.146
	Mid-Peak Period	4.646
	Off-Peak Period	3.646
47		5.127
49		5.357
75		
	Secondary(1)	
	On-Peak Period	4.629
	Mid-Peak Period	4.229
	Off-Peak Period	3.629
	Primary(1)	
	On-Peak Period	4.585
	Mid-Peak Period	4.185
	Off-Peak Period	3.585
	Subtransmission(1)	
	On-Peak Period	4.540
	Mid-Peak Period	4.140
	Off-Peak Period	3.540

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 125 (Continued)

ADJUSTMENT RATES (Continued)

Schedule		¢ per kWh
83	On-Peak Period	3.425
	Mid-Peak Period	3.025
	Off-Peak Period	2.425
85		
	Secondary	
	On-Peak Period	3.319
	Mid-Peak Period	2.919
	Off-Peak Period	2.319
	Primary	
	On-Peak Period	3.289
	Mid-Peak Period	2.889
	Off-Peak Period	2.289
89		
	Secondary	
	On-Peak Period	4.629
	Mid-Peak Period	4.229
	Off-Peak Period	3.629
	Primary	
	On-Peak Period	4.585
	Mid-Peak Period	4.185
	Off-Peak Period	3.585
	Subtransmission	
	On-Peak Period	4.540
	Mid-Peak Period	4.140
	Off-Peak Period	3.540
90		
	Primary 30-250 MWa	
	On-Peak Period	4.290
	Off-Peak Period	3.540
	Primary >250 MWa	
	On-Peak Period	4.290
	Off-Peak Period	3.540
	Subtransmission 30-250 MWa	
	On-Peak Period	4.504
	Off-Peak Period	3.708
	Subtransmission >250 MWa	
	On-Peak Period	4.242
	Off-Peak Period	3.708

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SCHEDULE 125 (Concluded)

91	3.714
92	3.968
95	3.714

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

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