BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

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Table of Contents

I. Introduction

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

A. My name is Maria Pope, and I am President and Chief Executive Officer of Portland General Electric Company (PGE).

My name is Brett Sims, and I am PGE's Vice President of Energy Supply.

Our qualifications are included at the end of this testimony.

Q. What do customers need to know about this request?

A. Our customers count on us to power their lives and businesses with safe and reliable electricity while we plan for – and deliver – a cleaner and more resilient energy future. We see every day, and in every condition, just how important the local system and infrastructure we operate is to residents and businesses in our service area. This is why we are committed to a collaborative partnership with stakeholders and customers to review our plans and make efficient use of resources as we work to provide a stable, secure, and modern energy grid.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to:

- Provide the context for PGE's 2025 rate case, including the circumstances and essential activities that make it necessary for us to file this case following the Commission's resolution of PGE's 2024 rate case, Docket No. UE 416 (UE 416). We will discuss the company's mission, strategic vision and priorities, and substantial, ongoing changes in our operating environment that continue to influence our strategy to deliver safe, reliable, and affordable electric service as part of a cleaner and more resilient energy future.

- Summarize the forecasted January customer price change of 7.4%, driven by critical expenditures necessary to ensure that our essential service remains safe and reliable in the face of increasing extreme weather events, and as we work to modernize and decarbonize the energy system. Key projects include significant battery storage facilities to support renewable power integration and provide reliable and critical capacity to meet peak customer energy demand, as well as further grid reliability and resiliency investments throughout our Transmission and Distribution (T&D) system.
- Present important policy proposals that seek to better align key regulatory mechanisms with resource adequacy requirements in an increasingly constrained regional energy market and decarbonization requirements. These proposals provide tools and flexibility to potentially mitigate the frequency of rate cases, increasing regulatory efficiency.
- Provide Commissioners, Staff of the Public Utility Commission of Oregon (Staff), and stakeholders a roadmap to help them evaluate our filing.

Our testimony is organized according to these primary objectives.

Q. How is the rest of your testimony organized?

A. After this introduction, we have five additional sections:

- Section II – Summary and Context
- Section III – Requested Change in Prices
- Section IV – Key Proposals and Structure of the Filing
- Section V – Closing
- Section VI – Qualifications

II. PGE Overview and GRC Context

Q. Please provide a brief description of PGE.

A. As a vertically integrated, regulated electric utility company, PGE proudly serves more than 920,000 customers across 51 Oregon cities. Our service territory encompasses 4,000 square miles, stretching from Mt. Hood to Grand Ronde and Yamhill County in the west, and from the Portland metropolitan area to south of Salem. Headquartered in Portland since 1889, we have more than 2,900 employees in communities across Oregon, making us one of the state's largest employers. We are a key economic engine for the state with the responsibility and privilege of providing essential electric service for our fellow Oregonians' homes, businesses, and public facilities.

Q. Please state PGE's mission and strategy.

A. PGE powers the advancement of society. We energize lives, strengthen communities, and foster energy solutions that promote social, economic, and environmental progress. Together with customers, communities and state and federal partners, we are creating a safe, reliable, clean, and accessible energy future. We are actively removing greenhouse gas emissions from our system, electrifying the economy from transportation to homes and buildings, and offering products and services that give our customers greater insights and flexibility to manage their energy use and costs. Our priorities remain centered on our customers, who drive us to continuously explore and innovate, deploy new technologies, simplify processes, and reduce costs to deliver a stable, secure energy grid, and an increasingly clean energy supply. The investments and actions reflected in this rate case are vital to fulfilling these commitments for our customers and communities.

Q. Have recent events underscored the importance of PGE's mission?

A. Yes. Our goal is to provide safe, reliable, and reasonably priced electricity that is increasingly clean and sustainable, while also managing the impacts of increased costs, repeated extreme weather conditions, catastrophic events, and volatile energy markets. The recent multi-day winter storm in January is just the latest example of severe weather events that PGE and our customers have experienced over the last few years. These have resulted in repeated new all-time load records, including the multi-day heat event in August 2023, which resulted in a new peak system high of 4,498 megawatts. This occurred only eight months after PGE customer demand set a new all-time high for winter in December 2022, breaking the prior record set nearly twenty-five years earlier. It remains clear that we must both plan for and invest to increase our capability and resiliency to adapt to the increasing frequency and severity of these events in both summer and winter.

Q. Please provide a summary of PGE's planned activities as a result of the rate increase in the last general rate case, UE 416.

A. We fully understand the significance and customer impact of the recently completed 2024 general rate case. The thorough review, diligent oversight and representation by Staff and stakeholders throughout the nearly year-long proceeding was invaluable to ensuring a robust process and achieving a fair and balanced outcome. The numerous settlements that PGE and the parties in UE 416 were able to reach were approved by the Commission only after they were determined to result in just and reasonable rates. The approved price change will allow PGE to strengthen the reliability and resiliency of its system.

More than half of the increase in 2024 was the result of prudently incurred power costs, which are a pass-through to customers and for which the company does not earn a return.

These power and fuel costs are reexamined annually through the Annual Update Tariff. The last case also included important capital projects that are serving customers today. With the approved price change that went into effect January of 2024, PGE will be able to perform critical work on behalf of our customers beginning this year. For example, in 2024, PGE will perform more than $52 million in routine vegetation management to protect public safety and our infrastructure by reducing the risk of vegetation-caused system damage and service outages.

Q. Please summarize why PGE is filing this rate case.

A. The timing of this rate case is essential as PGE continues to make necessary capital investments on behalf of our customers that were not in service or included in the last rate case. These vital actions include the installation of two major battery storage projects that will help balance and shape energy to meet peak customer demand and integrate renewable resources, as well as ongoing investments in T&D for reliability and resiliency. The investments included in this rate case will begin serving customers this year and early next.

Across all aspects of our company, we are working to ensure that we make investments and operate our systems with a keen awareness of the service and cost impacts on those we serve, especially our most vulnerable customers and underserved communities. Ultimately, we believe the actions we are taking to realize a cleaner, more flexible, and more resilient energy grid will benefit all customers, but we cannot lose sight of the near-term price impacts on those least able to afford them, and the importance of continuing to advance efforts to help reduce the energy cost burden on those customers. These efforts are described in further detail in my testimony.

Q. What are the drivers for this filing?

A. The predominant drivers of this rate case are capital projects including battery energy storage systems, which are expected to be placed into service at the end of 2024 and in mid-2025, as well as new and upgraded T&D infrastructure. These resources are essential to delivering reliable service to our customers while also making necessary progress toward decarbonization mandates and grid transformation.

Q. Is PGE proposing policy changes to provide flexibility to potentially mitigate the frequency of rate cases in the future?

A. Yes. We are proposing an investment recovery mechanism that could provide some flexibility to mitigate the frequency of rate cases. These are important investments that are essential for the safety, reliability, and resiliency of our system and will be needed in the years to come. The mechanism would apply to investments needed to sustain the energy supply system, not for new load-related expansion, and would not be used in years when PGE files a rate case. We further propose a sunset date for the mechanism to facilitate a review of the mechanism's effectiveness and address any necessary modifications. This proposed mechanism preserves regulatory oversight and enables efficient deployment as discussed further in PGE Exhibit 400.

Q. Are there other policy changes that PGE is seeking?

A. As we look ahead to participation in a future day-ahead market, PGE proposes to use a parallel proceeding to address the need for modernization of the existing Power Cost Adjustment Mechanism (PCAM). The current PCAM is increasingly incompatible with ambitious resource portfolio changes in accordance with House Bill 2021, as well as advancing regional market and reliability frameworks (day-ahead market and resource adequacy program).

We view this as an essential component of our preparations to effectively engage in West-wide market transformation efforts that, in turn, are vital to achieving greenhouse gas reductions while maintaining resource adequacy and service reliability for customers.

While not addressed specifically in this rate case, these actions in support of market transformation also point to our continued investment in our transmission system, including PGE's own transmission for last-mile load service from resources on and off our system, our longstanding collaboration with the Bonneville Power Administration (BPA) to bring power from across the region into PGE's service area, and our active engagement with developers and sponsors of regional and interregional projects to expand access to diverse and low-cost renewable resources like Montana and Wyoming wind or solar from the desert Southwest. Decarbonization requires diversification, and that requires both market transformation and a robust, flexible transmission system to support it.

Q. Are there other policy changes PGE plans to seek outside of this case?

A. PGE continues to experience significant growth in the industrial and high-technology customer segment, which is expected to accelerate over the next several years due to exponential increases in demand for data storage and computing power to support artificial intelligence (AI) and other advanced applications, as well as new investment growth spurred by landmark federal legislation (Creating Helpful Incentives to Produce Semiconductors Act (CHIPS), Inflation Reduction Act (IRA), and the Infrastructure Investment and Jobs Act (IIJA). While this growth is expected to provide significant economic growth and benefits to our communities, it will also present new challenges for PGE and the electric grid. Successfully meeting this growth will require careful planning and new approaches to reduce cost impacts and overcome system and resource constraints.

To meet this opportunity, PGE plans to seek changes to tariff provisions related to large customers connecting to PGE's system through the Commission's UE 430 docket, providing the foundation for new business processes and customer agreements. The tariff will outline the general requirements and applicability, while the customer agreement will provide the specific contractual terms and conditions between PGE and the customer. In UE 430, PGE will also provide clarity on how demand capacity may be limited and allotted based on transmission constraints. PGE plans to make its filing by the end of March 2024.

In addition, PGE plans to seek changes that improve demand response programs and flexible load incentives applicable to large customers. We currently anticipate a spring 2024 filing with the expectation that the changes take effect prior to the effective date of this case.

Q. Are there any other changes PGE plans to seek outside of this case?

A. Yes, PGE plans to file with the commission in a separate proceeding to reclassify its 57 kV networked assets from distribution to transmission. We previously reclassified PGE's 115 kV networked assets from distribution to transmission. Reclassifying the networked 57 kV assets will align PGE's asset classification with PGE's operations of these facilities, close the current gap between the definition of transmission and the definition of distribution,[1] and benefit PGE's cost of service customers through third-party transmission revenues credited in retail electricity prices. Reclassification of PGE's 57kV assets to transmission will also better align with industry standards and the classification of these assets by utilities.

Q. What external challenges is PGE facing as this rate case is filed?

A. As we have already noted, and previously documented in UE 416, it continues to be a time of extraordinary challenge and transition. Climate change and extreme weather events, shifting

[1] Order No. 19-400 defines transmission as non-radial line segments of 100 kV or higher voltage. Order No. 22-083 accepted PGE's DSP that defines distribution as at or below 35 kV.

economic conditions, geo-political instability, volatile energy markets, decarbonization policies, evolving customer expectations, and growing constraints in regional energy supplies are compounding uncertainty for PGE and our customers. Through these challenges, we have effectively managed costs within our control and worked to counter energy market volatility. For example, from January 2019 through 2023, PGE's power cost customer price increases totaled just over 16% or an average of roughly 4% per year. Over the same period, Mid-C forward power price curves increased on average by 226%.

These market dynamics are part of a larger context of transformation in western energy markets: as utilities throughout our region embrace new clean energy technologies and beneficial electrification to reduce carbon emissions, regional capacity supply has tightened and frequently reaches critical levels during peak events, and energy prices regularly rise to unprecedented levels during high-demand periods. While we are hopeful that continued technology development and diversification will reduce costs and risks over the long term, we expect the current challenges to persist through 2025 and beyond.

The investments and policy changes that we propose in this case are intended to strengthen PGE's position as a nimble, customer- and community-focused partner while navigating this challenging atmosphere.

Q. How is climate change affecting PGE and our customers?

A. Across our region, and globally, weather patterns have changed and are continuing to shift every year. Ever-increasing severe winter storms (wind, ice, floods), intense and prolonged summer heat, and growing weather variability have significantly affected customer heating and cooling demand, resulting in increased summer and winter peak loads and higher costs to serve customers during these times.

Our aggregate load patterns are changing as our service territory experiences fewer heating days and more cooling days on average, with extreme heat and cold contributing to higher peak loads in both summer and winter. We expect our winter and summer peak loads to continue to grow. Before 2022, PGE's peak load record held for nearly 25 years – now, we are seeing new records set almost annually, with a new winter peak load record set in December 2022 and new summer and all-time system peaks set in June 2021, and then again in August 2023. Continued load growth combined with a higher frequency of extreme weather patterns and a tight regional supply balance has also resulted in record high wholesale energy market prices and volatility.

At the same time, more frequent extreme weather conditions create more natural disasters and wildfire dangers, increasing security risks, emergency management costs, and mitigation needs. These drive the need to harden and protect critical energy infrastructure through sustained, conscious commitment and investments that will benefit our customers and communities over decades, not just years.

Q. Could you provide more context?

A. One example is the recent ice, snow, wind, and freezing temperature event in January that caused outages for more than 165,000 customers at its peak and required over 524,000 customer outage restorations in total. This multi-day event was the coldest in 30 years with a combination of record low temperatures and wind chill factors, prompting an emergency declaration by the Governor due to threats to life, safety, and property. This regional weather event created extremely high and volatile wholesale energy market prices with Northwest bi-lateral and Energy Imbalance Market (EIM) prices reaching $1,000 per megawatt hour (MWh) and California Independent System Operator (CAISO) prices reaching as high as

$2,000 per MWh during the event. Yet, through coordinated efforts between PGE's plant operations, power operations and balancing authority, we ensured sufficient energy supply for customers. Due to the extreme and widespread nature of this event across the Northwest and Rocky Mountain areas, regional electricity supplies were stretched to deficit levels, prompting several other utilities to declare an Energy Emergency Alert (EEA). We also saw the benefits of recent investments such as the Advanced Distribution Management System at our Integrated Operations Center, which provided greater visibility into the distribution system to keep power flowing across the distribution network in certain locations even while transmission lines and substations were de-energized by downed trees.

Q. How are customer growth and customer expectations affecting PGE?

A. While slowed population growth and downward pressure on new construction due to the current interest rate environment have resulted in modest residential customer growth, we expect recovery to begin in 2025. We are also seeing an exponential increase in interest for large customer connections. Strong growth in deliveries to industrial customers related to high-tech expansion and new data centers continues to drive total energy delivery growth in PGE's service area, projected at 3.2%, with important implications for PGE and our customers.

Increased beneficial electrification across society, spanning everything from cars and trucks to building heating and kitchen stoves, is also creating more awareness for customers of the essential role electricity plays in their lives and contributing to the load growth we see in our region. As a result, customers are increasingly interested in tools and services that allow them to manage their electricity costs and be more active participants with their energy usage. Customers also expect safe, reliable power that is increasingly clean. Meeting these expectations requires thoughtful planning, strategic investments, effective resource deployment, and corporate financial stability and responsibility to do so affordably.

Q. What efforts has PGE made to help customers meet their clean energy goals?

A. While PGE is rapidly evolving its generation mix to meet HB 2021's targets, we support customers interested in moving to renewable and non-emitting generation on a faster timeline. These efforts build on the success of our Green Future Choice program: approximately 29% percent of eligible residential PGE customers have enrolled in this voluntary, renewable energy certificate program. We also offer Green Future Enterprise and Green Future Impact, which allow our larger customers to meet sustainability and climate goals with a mix of non-emitting and renewable resources.

In the coming years, we expect increasing interest in rooftop solar as more residential customers take advantage of tax credits and incentives, such as the 30% federal tax credit for the installation of new solar panels and/or storage systems and various state and local incentives for these technologies, including the Oregon Solar + Storage Rebate program and the Solar Within Reach program.[2] For residential customers interested in generating their own electricity, we have made significant improvements to our interconnection process for rooftop solar installations. We implemented the Fast Track process for Level 1 applications, reducing the approval time from 13 business days to three. We enhanced training for our customer service associates on the interconnection process so they can provide faster answers to interconnection questions while avoiding the need to transfer customers to the net metering team. An online payment option was also implemented for customers, and we implemented

[2] The Inflation Reduction Act of 2022, Pub. L. No. 117–369, §25D, 136 Stat. 1818, extends and modifies the Residential Clean Energy Credit and applies to property installed before 2035. The Oregon Solar + Storage Rebate Program offers Oregon homeowners rebates of up to $5,000 for solar electric systems and up to $2,500 for energy storage systems, with greater funding available for low and moderate income Oregonians.

automation steps for timely processing in the billing system. In 2024, we are taking steps to further improve the customer experience by integrating the PowerClerk system into our customer management system, C2M, which enables faster validation of customer details on interconnection applications, improving processing time. We are also implementing over-the-air meter configuration changes, so the meter does not need to be replaced when a customer installs rooftop solar, and further automating the account and billing setup. Finally, we are implementing a new portal on our website, so customers have quick and simple visibility into the status of their interconnection application. We expect these changes in 2024 to significantly reduce PGE's cycle time for processing rooftop solar applications.

The programs and initiatives in PGE's 2023-25 Transportation Electrification Plan, accepted by the Commission in October 2023, further illustrate our support for customers' efforts to embrace a clean energy future. These initiatives, including related proposals in this rate case for changes to TE tariffs, support system transformation to be cleaner, more flexible, and more efficient in its use of resources.

Q. Please describe further some of the efforts PGE is taking to manage costs in the context of volatile energy prices and constrained regional energy markets.

A. PGE is continually looking for opportunities to reduce risk for our customers as we manage and evolve our wholesale energy market practices to address changing market conditions. As part of these efforts, we have expanded our regional strategy, seeking partnership opportunities that leverage organizational synergies and yield net benefits for customers. Agreements with Douglas County Public Utility District (PUD), Grant County PUD and wholesale industrial energy users are helping to remove emissions from our portfolio while improving flexibility and cost-effectively supporting reliability and resource adequacy. At the same time, continued diversification and decarbonization of PGE-owned resources are similarly benefiting customers. Our new Clearwater Wind Farm in Montana illustrates the advantages of bringing wind resources from outside the Columbia Gorge region into our portfolio and is expected to result in an approximate $28 million annualized decrease to customer prices beginning later in 2024.

Plant operational efficiencies allow for increased availability during peak demand periods for PGE-owned plants with only moderate cost increases for generation O&M. At our wind plants, we remotely monitor our equipment's condition in real time, which allows us to take necessary actions and anticipate equipment replacement needs, resulting in reduced downtime.

PGE also continues to provide leadership and actively engage in regional efforts to enhance system diversity and provide additional tools to manage costs and mitigate market volatility through organized market expansion (day-ahead market) and establishment of a West-wide regional resource adequacy program. Efforts like these, in conjunction with PGE's robust and diverse portfolio and system and our Integrated Resource Plan (IRP)/Clean Energy Plan (CEP) planning efforts, position PGE to decarbonize and maintain reliability for customers while navigating increasingly volatile wholesale market conditions and prices on behalf of customers.

Q. How does this filing demonstrate PGE's commitment and approach to the clean energy transition?

A. The actions outlined in this filing represent the thoughtful and comprehensive planning and disciplined execution needed to be successful in implementing the clean energy transition reliably and affordably. This includes effectively managing and mitigating the impacts of higher labor and supply costs while investing in clean and diverse, non-emitting resources such as the Constable and Seaside battery storage installations, and other resource modernization efforts. Additionally, we have proposed important modifications to certain regulatory mechanisms, including the investment recovery mechanism and PCAM modernization (in a parallel proceeding), which together create better overall alignment with achieving decarbonization targets and adapting to rapidly changing market dynamics.

Another key component of our clean energy transition is the ongoing advancement of our Virtual Power Plant (VPP). The VPP will support customers' freedom and flexibility to make their own energy choices while enabling PGE to manage distributed energy resources (DERs) and flexible loads interconnected to PGE's system to supply a host of energy and capacity services. The VPP is an important tool for identifying and delivering DER and flexible load benefits to our customers and community partners who seek equitable and local clean energy options. Through the VPP, DERs and flexible loads can help us reduce the cost of achieving decarbonization requirements, advance customer and community energy resiliency, promote customer engagement with the energy system, and unlock additional grid services that enable our Distribution System Plan[3] vision of a dynamic bi-directional network.

Q. How does this rate case further your strategic vision?

A. This rate case contains important investments necessary to maintain safe, reliable, and affordable service**,** while better aligning regulatory frameworks with decarbonization and resource adequacy imperatives, all of which are central to our strategic vision. Our investments in infrastructure to meet customer growth are coupled with smart grid technologies utilizing an energy platform that will meet changing customer expectations and

[3] *See* https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning.

support reliability and advanced resource planning. It will aggregate the expansion of local and remote generation, flexible loads, communications, and information technologies to help us more rapidly advance decarbonization at a lower cost while providing new and more compelling service options for customers.

Continuing to enhance cyber and physical security is critical for a safe, reliable, secure, and resilient electric system. Further, we have taken important steps through numerous individual projects, large and small, to modernize, strengthen, and upgrade our T&D system for customer growth, enhanced reliability, and resilience. The investments reflected in this rate case will meaningfully contribute to the realization of our strategy to deliver a clean energy future while operating in an uncertain and dynamic environment and delivering exceptional value for our customers.

Q. Specifically, how do PGE's new batteries contribute to PGE's strategic vision?

A. The Constable and Seaside battery installations are investments that will help maintain reliability while enabling integration of carbon-free and sustainable energy into our mix for years to come. These facilities join a broader emissions-free capacity resource portfolio that also includes, via a 20-year storage capacity agreement, a similar 200 megawatt, four-hour battery installation located at a key substation in Troutdale, which PGE contracted through the same RFP process in which we acquired Seaside and Constable.

III. Requested Change in Prices

Q. Please summarize PGE's requested price change.

A. We request a base business price increase of $202.0 million. Combined with PGE's proposed power cost increase requested under Docket UE 436 and our current forecast of supplemental schedules, we anticipate an overall price increase of 7.4%, effective January 1, 2025. Paired with the proposed refund of investment tax credits associated with the earlier described battery storage projects, PGE expects a 0.1% price reduction on June 1, 2025, resulting in a total anticipated price change of 7.3%.

Q. What are the primary elements of PGE's requested price change?

A. As discussed above, our request is centered on investments and expenditures made to provide system reliability and resiliency, safety, and security for our customers. These include two major battery storage facilities, described in detail in PGE Exhibit 500, to serve customer needs and facilitate integration of additional emissions-free renewable resources into our generating mix. We have also made other critical investments and enhancements to our T&D system, operations, services, and engagement to advance a clean energy future where all PGE customers and communities are able to fully participate and benefit. PGE recognizes this price increase follows the recent large increase that resulted from UE 416. We are very mindful of the impact these increases have, and the essential role electricity plays in the lives of our customers and the health and vitality of our communities.

It is important to note that while current forecasts call for Oregon's economy to experience a soft landing rather than a recession, uncertainty remains high, and recent historic levels of inflation have reset operating costs at a higher level that must be accounted for in our budgets. The rate of price increases across the economy that impact the cost to operate our business and serve customers has moderated, but not reversed.

Q. What is the landscape of U.S. utility rate cases?

A. U.S. rate case activity has been at high levels for the past three years. Similar to PGE, electric utilities across the U.S. are making investments for the resiliency and decarbonization of the grid and to address increasing capacity shortages in energy markets. According to S&P Global, the common trend reflected throughout electric utility filings is significant capital expenditures to upgrade T&D systems and install technologies needed to accommodate the transition to clean energy:

> Spending is driven by pent-up demand to replace and modernize aging infrastructure, renewable portfolio standards of multiple states — which include large expansions in low-carbon energy generation capacity — continuing to ramp up, and federal infrastructure investment plans that are intended to steer conversion of the nation's power generation network to zero-carbon sources by 2035.[4]

Again, similar to PGE, utility capital expenditures across the nation are also being driven by economic stimulus and resulting growth in electric energy demand and investment driven by federal legislation, particularly the Inflation Reduction Act (IRA), CHIPS Act and Infrastructure Investment and Jobs Act (IIJA).

Q. Are there any notable, maturing issues facing utilities at this time?

The increase in severity and frequency of wildfires and other extreme weather events in the U.S. has had immense impact on the residents of the affected areas, our customers and PGE. We have engaged and worked closely with a broad set of stakeholders including the Oregon Department of Forestry, the US Forest Service, local fire agencies, and local fire districts to inform the Wildfire Mitigation Plan that was filed at the end of 2023 to be approved by the

[4] SPglobal.com/marketintelligence, February 5, 2024.

Commission and which outlines our risk assessment and mitigation strategies. While our Wildfire Mitigation Plan is robust and informed by data, technology, and community engagement, with the changes in the liability landscape and lack of clarity on potential claims arising from wildfire litigation, utilities have effectively become insurers of last resort for what is a broader societal challenge involving global climate change, forest management choices, invasive pests and land use decisions.

Q. How are other utilities working to mitigate the risks from wildfire liability?

A. Utilities in a number of states are working with legislatures and regulators to attempt to address impacts and lower their risk exposure from these events, adopting new processes, and procedures. California approved securitization as an option to address the liability costs from catastrophic wildfires, with the California Public Utility Commission approving the use of securitization for wildfire-related liability costs. As part of a sweeping wildfire mitigation proposal, Hawaii is currently evaluating legislation that will authorize utility fee securitization and may apply to past property damage claims.

Bills introduced in Hawaii and Utah would create wildfire funds to supplement or replace other insurance for making wildfire damage payments, similar to the California Wildfire Fund adopted in 2019. Some states, like Alaska, are considering adoption of legislation that would ensure utilities are not held liable for certain wildfire damage. In addition, a constructive regulatory model is the compact that enables some of the lowest-cost funding from debt and equity holders and establishes the stability that rating agencies rely upon. It is important that all reasonable solutions should be on the table for consideration and potential adoption.

We are aware that PacifiCorp, another Oregon electric utility, recently filed a rate case in which it is seeking Commission approval for both an Insurance Cost Adjustment and a

Catastrophic Fire Fund to help address the risk exposure from wildfires and the lack of insurance to indemnify against that risk.[5] While PGE is not proposing similar mechanisms at this time, we continue to explore options to address the real risks to our customers and PGE and we will seek in a future process to work with the Commission to identify and explore potential options including sources of funding, relative contributions between customers and shareholders, and limits on liability.

Q. How does this rate case reflect your commitment to continue to improve operations and effectively manage costs?

A. We remain focused on carefully managing costs, streamlining processes, implementing best operating practices, and maintaining a culture of continuous improvement that benefits customers through increased value and reduced cost over time.

We have reduced our total recordable incident rate for worker injuries by 63.6% in the last five years, which helps avoid higher workers' compensation costs. As a result, claims costs decreased by more than 31% from 2018 to 2023, and lost time for labor also declined over this time. Further, to manage declining labor availability, PGE has made investments at our Sherwood Training center, enhancing our ability to hire and train additional PGE crew personnel, with 43 employees currently in our pre-apprentice/apprentice pipeline, which will help reduce third-party contract crew costs over time and improve our ability to meet customer growth and respond to extreme weather events and outages.

PGE's power cost strategy has also continued to evolve and adapt in response to increasingly volatile energy markets. We have executed structured transactions and partnering arrangements – such as our recent contracts with BPA and the Grant and Douglas PUDs in

[5] Docket No. UE 433.

Washington – that reduce costs, diffuse risk, hedge against extreme market conditions, and provide shaping and flexible capacity to meet peak needs.

In addition, over recent years, we have deployed secured cloud-based services such as Oracle Enterprise Resource Planning (ERP), Oracle Utilities Analytics (OUA) and other projects to migrate, centralize, manage and use data that provide us with a new level of flexibility in how we manage and organize IT capabilities and reduce costs as compared to the traditional on-premises approach. Migrating to OUA saved $115,000 while transitioning to Oracle ERP saved $3.2 million over five years before considering productivity improvements from the use of better software. The use of this technology increases efficiency, reduces enterprise risk and increases financial transparency, enabling better-informed financial decisions.

Q. How does PGE help customers mitigate price impacts by managing their energy use?

A. We offer a suite of tools for customers to manage their energy usage and help mitigate their bill impacts. For example, for residential customers, PGE offers a Time-of-Day pricing program that enables customers to shift energy usage to off peak hours and take advantage of lower prices, and a Peak Time Rebate program that compensates customers for reducing their electrical energy use during peak event hours. Other programs such as Smart Thermostat and EV Smart Charging provide options for lowering usage during peak periods, and in Q4 2023 we updated our Energy Tracker tool to help customers better understand and manage their energy use.

We are adding new features to Energy Tracker to give customers greater insight through individual data and personalized recommendations and tips to help them reduce usage and costs. Our call center representatives are also equipped to help educate customers on their energy use and connect them with additional resources available via the Energy Trust of Oregon (ETO). For multi-family, PGE offers a Multi-Family Water Heater program to adjust water heating to times when demand is low, reducing customer costs while also giving PGE more options to cost-effectively balance our resources.

For small and medium commercial customers, PGE offers a Smart Thermostat program that adjusts the thermostat between one to three degrees during peak load events to reduce costs of participating customers. We also offer energy audits for commercial customers to help them reduce their use and improve efficiency. Lastly, large commercial and industrial customers can participate in PGE's Energy Partner program to be voluntarily curtailed based on their chosen load-curtailment plan. In total, nearly 180,000 residential customers (more than 20% of all PGE residential customers) are participating in and benefitting from our demand response and flexible load programs, with very real results. During last summer's August heat event, we were able to activate an all-time high of 90-plus megawatts of customer flexible load to help maintain reliability and reduce power costs overall and for participating customers.

PGE's Distribution System Plan calls for us to expand our flex load portfolio to 211 megawatts of summer and 158 megawatts of winter demand response by 2028, complemented by approximately 150 average megawatts of incremental cost-effective energy efficiency. Our energy efficiency goals reflect our partnership with ETO and a comprehensive action plan. PGE and ETO have developed to collaborate on efforts like the Flexible Feeder Initiative to target energy efficiency measures that can complement flex load offers, benefiting PGE's system while also creating opportunities for customers to manage energy use and save money.

These efforts are central to meeting our decarbonization goals while also maintaining affordability for all customers.

Q. Please explain PGE's programs to help keep electricity affordable for low-income customers.

A. PGE takes the needs of and impacts to our low-income customers very seriously. In addition to our support for long-standing assistance through the federal Low Income Home Energy Assistance Program (LIHEAP) and the ratepayer-funded Oregon Energy Assistance Program, we were proud to support House Bill 2475 (HB 2475) during the 2021 legislative session. This allowed – for the first time – the state's investor-owned utilities to provide discounts based on customer income. PGE launched the first Income-Qualified Bill Discount (IQBD) program in Oregon. Other utilities have followed suit, and we are pleased that regulators, stakeholders, and other interested groups have supported this important work to provide bill relief across the state. We recognize and support the need for bill discount programs and other energy assistance, as supported by the adoption of PGE's IQBD program. As of February 2024, over 75,000 active IQBD participants—more than 8% of our residential customer base—receive discounts on their bills with savings totaling more than $20 million since the program launched. In 2024, we anticipate increasing enrollment to 100,000 active participants. Notably, we have prioritized simplicity and efficiency in our IQBD program. Through collaboration with the Oregon Housing and Community Services Department, we have removed a significant barrier to entry for eligible customers through the application process. We want all customers who are in need and eligible for this program to have a simple and straightforward path to enrollment, and we have partnered with a range of organizations to increase awareness and promote our IQBD program.

Q. What changes has PGE made to its IQBD program, and what plans does PGE have to further address the needs of its energy-burdened customers in the future?

A. As of January 1, 2024, we increased the maximum bill discount to 60%, more than doubling the previous maximum discount of 25%. PGE's discount is now higher than the maximum discount offered by other Oregon utilities. Since we began offering higher discount options for IQBD, 12% of eligible customers are participating at the 60% discount level and 10% of eligible customers are enrolled at the 40% discount level.

In addition, through our 2023 wildfire mitigation plan, PGE provides no-cost portable batteries to those IQBD-eligible customers with medical certificates residing in high fire risk zones. Based on feedback, we are currently partnering with Meals on Wheels for the delivery and set-up of these portable battery devices for our most at-risk customers in 2024.

We are also carrying awareness of challenges faced by energy-burdened customers across other areas of our business. Our proposed revisions to our tariff governing public charging rates for electric vehicles, for instance, include a 20% discount on retail Schedule 50 rates for IQBD customers. The discount (see PGE Exhibit 900) will be available through the charging station app and will automatically be applied when they enter their PGE account number or phone number tied to their account.

Additionally, PGE is conducting an Energy Burden Assessment (EBA, formerly referred to as a low-income needs assessment, or LINA) in 2024, to gain deeper insights into the energy assistance needs of low-income customers we serve, based on customer-level geographic, demographic and building data. We've retained a third-party to conduct the EBA and solicited feedback from Staff and other stakeholders on the proposed study components, and deliverables. We anticipate that the data produced by the EBA will allow us to compare customers' needs to actual low-income assistance program performance and thus can help us inform rate design, customer offerings, outreach and tariffs – all to increase the accessibility and affordability of our services.

Q. Is PGE interested in continuing to evolve its low-income programs?

A. Yes. While PGE has supported low-income energy assistance programs for years and has guidelines in place for energy assistance referrals – which support qualified customers getting in touch with agencies with available funding to help with their utility costs – this programmatic, tariffed approach is relatively new. We are proud of what we have accomplished so far and will continue to monitor the effectiveness, costs, and benefits of the IQBD and other programs. Results from the EBA should allow us to further programs to meet low-income customers' needs, potentially as a part of a more holistic discussion of energy assistance policy more generally. We intend to file with the Commission in Q3 2024 further updates to our discount program, informed by the EBA. This filing will be conducted in a separate docket to maximize focus and opportunities for engagement by energy justice communities.

Q. In addition to working to deliver programs and services more equitably to members of under-resourced communities through programs such as IQBD, is PGE also working to incorporate principles of energy justice into its business, decision making and operations?

A. Yes. PGE is committed to integrating energy justice into our business at all levels. By this, we are referring to procedural justice, distributive justice, and restorative justice. These require us to incorporate historically excluded perspectives by bringing community voices to the decision-making table, to equitably distribute the benefits and burdens of energy infrastructure and systems, and to repair past and ongoing harms caused by energy systems and decisions. Our approach to these efforts is described in detail in recent PGE planning documents, such as our 2022 Distribution System Plan.[6] It's also reflected in organizational changes we've made to ensure we act on and track progress toward, our commitments. At an organizational level, PGE has established a Community Engagement team to develop and implement strategies that support both PGE's business and the goals and aspirations of the communities we serve, particularly those representing underserved, under-resourced, or underrepresented populations. The Community Engagement team also manages the newly-established Community Benefits & Impacts Advisory Group (CBIAG) and works closely with other teams across the company to drive consistency and internal alignment in external engagement.

Q. Is PGE pursuing other funding options to reduce cost pressure on customers?

A. Yes. The Oregon Bipartisan Infrastructure Law (BIL) and the Federal IRA have provided unprecedented levels of government grant funding, tax credits and incentives for a wide array of grid investment and clean energy development. In 2023, PGE was (directly, or indirectly as a sub-recipient) awarded more than $300 million in grants, exceeding all other utilities. The successful grants include Bethel-Round Butte reconductoring, which will enable renewable resource development on the reservation of the Confederated Tribes of Warm Springs, the deployment of next generation customer meters to support customer renewable energy integration and grid management, the creation of a hydrogen hub, and the creation of quality jobs to support the future clean energy workforce.

Many of these grants include a focus on providing benefits to disadvantaged communities, and PGE has taken a leadership role in building connections to career learning

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[6] *See* Chapter 2 of PGE's DSP, available online at portlandgeneral.com/dsp.

and support for the clean energy workforce within its grant applications. For instance, the Oregon Clean Energy Workforce Coalition, which PGE launched in 2022 to help build equitable inclusive career pathways, was selected last year to receive a grant of nearly $3 million from the U.S. Department of Labor. The grant will support the development of a skilled, diverse and robust clean energy workforce.

Q. Can you discuss further PGE's efforts on grant funding?

A. In 2024, PGE continues to apply for funding to maximize the amount of federal dollars coming to Oregon and our service territory. As of January 12, 2024, we have submitted seven concept papers or grant applications totaling $335 million in requests for Department of Energy (DOE) Grid Resilience and Innovation Partnerships funding where PGE is directly involved, either with in-kind labor or cash that would be partially offset by federal grant dollars, and another $2.35 billion where PGE is named as a supporting entity in other parties' applications. We also worked with Clackamas County to submit a $50 million application for the Federal Emergency Management Agency (FEMA) Building Resilient Infrastructure and Communities (BRIC) program that would underground portions of our power lines near Mt. Hood, an area susceptible to multiple severe weather conditions and catastrophic events. These funding requests and awards support investments in transportation electrification, grid resiliency, climate and wildfire adaptation and resiliency, clean energy, smart grid investment, carbon reduction, hydrogen, expanded and advanced energy efficiency and job creation.

Q. Will the results of this rate case affect PGE's future access to and cost of capital to fund investments, including PGE's contributions to projects partially funded by federal grants?

A. Yes. As described in PGE Exhibit 600, the results of this case, as filed, will be important to PGE's ability to cost-effectively fund projects, meet financial obligations, and provide an opportunity for our providers of capital to receive a reasonable return on their investment. This in turn benefits our customers by giving investors the incentive to provide access to low-cost capital that supports the delivery of reliable, fairly priced service to customers. Achieving decarbonization targets that are critical to addressing climate change and required in accordance with Oregon's mandates under HB 2021, as well as ensuring resource adequacy and reliability at the least cost as we transform the energy system, depends on investor support and access to significant new funding from capital markets.

IV. Key Proposals and Structure of the Filing

Q. Please summarize the specific proposals you are requesting the Commission approve as part of this general rate case.

A. We request the Commission approve the following requests:

- Approve an increase to our revenue requirement for base rates by $202.0 million on January 1, 2025. This request is discussed in more detail in PGE Exhibit 200;
- Approve PGE's incremental capital investments of $878.2 million for the January 1 price change, resulting in a total rate base of $7.5 billion as described in the testimony of various witnesses in this case;
- Approve a tracking mechanism for the Constable Battery Energy Storage Project should the project come online in early January 2025. The revenue requirement and rate base for Constable are already included in the values above and the project is described in further detail in Exhibit 500;
- Approve a tracking mechanism for the Seaside Battery Energy Storage Project anticipated to come online in the first half of 2025. The revenue requirement, inclusive of power costs, for Seaside is $49.5 million, and rate base of $369.7 million and the project is described in further detail in Exhibit 500;
- Approve PGE's proposal to amortize the value of the battery storage investment tax credits to customers over a five-year period as described in Exhibit 500. This will result in amortizing approximately $51.5 million to customers through a separate schedule in 2025;

- Approve an overall cost of capital of 7.19% percent, which is comprised of a capital structure of 50% equity and 50% long-term debt, and an ROE of 9.75% as described in PGE Exhibit 600;
- Approve PGE's proposed investment recovery mechanism to increase efficiency and reduce the need for annual rate case filings while maintaining robust regulatory oversight, as described in PGE Exhibit 400;
- Approve renewable automatic adjustment clause (RAAC) changes, discussed in more detail in PGE Exhibit 500;
- Approve the rate spread and rate design as proposed in PGE Exhibit 900.

Q. Do you have other key proposals or requests that you will file concurrently with this rate case?

A. Yes. We are filing an Annual Update Tariff (AUT) for recovery of the 2025 NVPC forecast. We are also submitting a separate filing with a revision request associated with Tariff Schedule 126, which implements PGE's PCAM.

Q. Why are you submitting these filings outside of the GRC filing?

A. We are submitting a separate AUT to simplify the GRC process since the NVPC forecast has its own separate procedural schedule and to more clearly isolate price impacts associated with PGE's base business versus power costs that get updated annually. For the PCAM revision, we submit our request as a separate filing to allow the Commission, PGE and parties to focus on this crucial mechanism, allow intervention from other utilities that may also be pursuing a PCAM revision, and provide a robust process for the Commission to review the relevant issues and arrive at a decision, according to an appropriate procedural schedule.

Q. What is your PCAM revision proposal?

A. In the Tariff Schedule 126 revision request, we plan to propose the following modifications:

1) Remove the current PCAM deadbands and share all prudently incurred annual Power Cost Variances[7] (PCV) between customers and PGE at a 95/5 ratio.

2) Recover or refund prudently incurred PCV with no application of an earnings test to such variances.

In the separate Tariff Schedule 126 revision request filing, we will discuss how the current PCAM structure does not appropriately balance the risks and rewards of power cost variability between PGE and our customers and, thus, why further modification to the PCAM is imperative. Further, that filing details how the current PCAM is incompatible with participation in an organized day-ahead market, regional resource adequacy program, and implementation of HB 2021 emissions reduction requirements, which provides significant benefits to customers in both the near and long term.

Q. How is PGE presenting this case?

A. We are presenting the following direct testimony:

- In Exhibit 200, Greg Batzler, Senior Regulatory Consultant, Regulatory Affairs and Jaki Ferchland, Senior Manager of Revenue Requirement, Regulatory Affairs summarize the $2,926.8 million test year revenue requirement as of January 1, 2025, comparing the request with that most recently approved in our last general rate case Docket No. UE 416 (2024 test year). This testimony also discusses the request for trackers for both battery energy storage projects, our net rate base, plus associated depreciation and amortization expense, and unbundled results.

[7] The annual Power Cost Variance is the difference for a given year between Actual NVPC and the NVPC forecast pursuant to Schedule 125, Annual Power Cost Update.

- In Exhibit 300, Anne Mersereau, Vice President, Human Resources, Diversity, Equity and Inclusion, Joe Trpik, Senior Vice President, Chief Financial Officer and Treasurer and Greg Batzler, Senior Regulatory Consultant, Regulatory Affairs discuss compensation and corporate support, including PGE's total compensation costs for the 2025 test year, which encompass total labor costs, incentive pay, and employee benefits.
- In Exhibit 400, Larry Bekkedahl, Senior Vice President Advanced Energy Delivery and Ben Felton, Executive Vice President and Chief Operating Officer, discuss T&D capital expenditures from January 1, 2024 through December 31, 2024, and incremental O&M activities and costs for the 2025 test year. They also provide information on Routine Vegetation Management (RVM), Utility Asset Management (UAM), and PGE's Virtual Power Plant initiative. Finally, they propose a new investment recovery mechanism for some of PGE's capital projects.
- In Exhibit 500, Ben Felton, Executive Vice President and Chief Operating Officer discusses the O&M expenses associated with PGE's long-term power supply resources and supports the investments PGE is making in two major battery energy storage system (BESS) projects – Constable and Seaside, as well as our proposal for amortizing the value of the ITC to customers. His testimony also supports use of the renewable automatic adjustment clause (RAAC) for associated stand-alone battery storage.
- In Exhibit 600, Christopher Liddle, Senior Director, Risk Management and Assistant Treasurer at PGE and Josh Figueroa, a Principal of The Brattle Group, recommend PGE's authorized cost of capital and capital structure for the 2024 test year.

- In Exhibit 700, Amber M. Riter, Economist and Lead Load Forecasting Analyst at PGE and Shannon M. Greene, Economist and Load Forecasting Analyst at PGE present PGE's 2025 test year energy and customer forecast.
- In Exhibit 800, Robert Macfarlane, Manager, Pricing and Tariffs, and Casey Manley, Senior Regulatory Analyst in Pricing and Tariffs describe the methodologies and results of PGE's updated generation and customer marginal cost of service studies.
- In Exhibit 900, Robert Macfarlane, Manager, Pricing and Tariffs, and Christopher Pleasant, Regulatory Consultant at PGE describe how the proposed tariff changes recover our 2025 revenue requirement to achieve fair, just, and reasonable prices for our customers, as well as price changes to various supplemental schedules.

V. Summary and Closing

Q. Please summarize your request and offer any closing comments.

A. PGE respectfully requests that the Commission approve the price changes and policy proposals described above and in our attached exhibits. These changes and proposals reflect the Company's ongoing commitment to reliable, affordable electric service as we continue to pursue the clean energy transformation our customers, the law, and the health of our communities require of us. We submit this request with an acute appreciation for the need to achieve this while managing our business to minimize costs and price increases and make efficient use of customer dollars, and we continue to operate with those priorities at the forefront of our efforts. We remain committed, as well, to ensuring that our service to customers, our operations, our pricing structures and our decision-making processes reflect the needs of all customers in an increasingly just and equitable system. We look forward to a robust review and discussion of our request.

VI. Qualifications

Q. Ms. Pope, please describe your educational background and experience.

A. I am President, CEO and a member of the Board of Directors of Portland General Electric Company, Oregon's largest electric company. Before becoming CEO in 2018, I served as PGE's senior vice president of Power Supply, Operations and Resource Strategy. In that role, I oversaw PGE's transition to the Western Energy Imbalance Market, a foundational step in creating a regional smart grid. I joined PGE in 2009 as the company's CFO. Prior to PGE, I was CFO of Mentor Graphics Corporation and have held senior operating and finance positions within the forest products and consumer products industries. I began my career in banking with Morgan Stanley.

I serve on the Secretary of Energy's Advisory Board, on the Executive Committee of the Edison Electric Institute, as Chair of the Electric Power Research Institute, and Chair of the Oregon Business Council. I am an alumna of the Stanford Graduate School of Business and earned my bachelor's degree from Georgetown University.

Q. Mr. Sims, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Business with a focus in Economics from Linfield College and a Master of Business Administration degree from George Fox University. Prior to being promoted to Vice President in October 2020, I was the Senior Director of Strategy Integration and Regulatory Affairs at PGE. I have also held other managerial positions in the banking, technology, and communications sectors prior to working at PGE.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Greg Batzler
Jaki Ferchland

February 29, 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. I am responsible for the development of PGE's revenue requirement forecast and other regulatory analyses.

My name is Jaki Ferchland. My position is Senior Manager of Revenue Requirement, Regulatory Affairs.

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 present PGE's 2025 test year forecast revenue requirement for the following components:

1) Base business costs to provide safe, reliable, and resilient energy for our customers; and
2) Constable Battery Storage (Constable) and Seaside Battery Storage (Seaside) facilities that provide reliability and help meet PGE's system capacity needs with non-emitting resources.

We provide a separate revenue requirement for Constable, expected to reach commercial operation on or around December 31, 2024, and Seaside, expected to be online June 1, 2025.

Q. What increase in base business revenue requirement does PGE request beginning January 1, 2025?

A. PGE requests a January 1, 2025 base business increase of $202.0 million or 7.3%,[1] inclusive of the Constable battery project and excluding the load-adjusted impact of net variable power costs (NVPC), which are a part of Docket No. UE 436 (UE 436). This increase is relative to anticipated revenue based on 2024 prices approved in Commission Order No. 23-386 in Docket No. UE 416 (UE 416), inclusive of PGE's currently forecast 2024 revenue requirement for Clearwater, as filed in Docket No. UE 427.

The revenue requirement proposed in this filing will allow PGE an opportunity to earn a 7.19% rate of return that includes a 9.75% return on average common equity (ROE) in 2025.[2] PGE Exhibit 201, columns 1 through 7, summarizes the development of PGE's 2025 revenue requirement for base business plus Constable. In addition to presenting this integrated (bundled) revenue requirement, we also present and discuss our unbundled revenue requirement in Section VIII.

Q. Are Constable and Seaside included in your request for $202.0 million of additional non-NVPC revenue?

A. Constable is included but Seaside is not. However, as shown in PGE Exhibit 201, columns 6 through 9, the incremental annualized revenue requirement increases for both projects are isolated, with Constable's revenue requirement forecast at $17.3 million and Seaside's revenue requirement forecast at $49.5 million.[3] PGE requests that the Public Utility Commission of Oregon (OPUC) authorize tariffs to collect these annualized amounts

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[1] Inclusive of 2025 Schedule 146 (Colstrip Power Plant Operating Life Adjustment) amounts in current and requested prices. This does not account for the costs and benefits of Seaside, expected June 1, 2025.

[2] As discussed in PGE Exhibit 600, PGE proposes a 50/50 capital structure between debt and equity.

[3] These amounts are prior to the reflection of income tax credits (ITCs), which PGE proposes to return to customers through a separate schedule over five years and represent a forecasted amount of approximately $51.5 million for 2025 under PGE's proposal, which is discussed in PGE Exhibit 500.

beginning with the online date of each respective battery storage facility.[4] We currently expect Constable to be online by December 31, 2024, and Seaside to be online June 2025. To the extent that the on-line date for either plant was to shift, the effective date of tariffs to track and recover the incremental impact of the plant changes accordingly. In Section VII, we discuss the incremental revenue requirements of Constable and Seaside.

Q. What does PGE currently forecast as a total customer price increase for 2025?

A. Including Constable, PGE's 2025 NVPC forecast filed in a separate docket, and all known changes to supplemental schedules,[5] PGE currently forecasts a 7.4% total price change effective January 1, 2025. After reflecting both the addition of Seaside in 2025 coupled with benefits from PGE's ITC proposal, we currently forecast a 7.3% total price change.

Q. How would approval of PGE's request benefit customers?

A. To address future reliability and grid resilience and to meet new and growing load, PGE must continue to maintain and upgrade the energy grid to continue providing reliable energy for our customers. PGE's request allows us to strengthen the system against extreme weather events that have become more frequent. The IT investments and virtual power plant (VPP) projects will expand the use of smart technologies that give customers more control over their energy use and make the energy grid more resilient against extreme weather and cyberattacks. The Constable and Seaside battery energy storage systems help address PGE's capacity needs, improve reliability, and support the clean energy transition as non-emitting resources, while our ITC proposal provides direct customer benefits offsetting investment costs.

[4] PGE currently expects Constable to be placed into service prior to January 1, 2025, and thus be included within a January 1, 2025 price change, but seeks a tracker for Constable should the in service date shift to January 2025. Similarly, PGE is seeking a tracker for Seaside, which is expected to be in service on June 2025.

[5] See PGE Exhibit 900 for additional details on supplemental schedules.

Q. In the absence of a price increase, what is PGE's expected regulated ROE for 2025?

A. Not accounting for the requested price increase, PGE's regulated ROE is expected to be approximately 5.29% in 2025 before Constable and Seaside are online, significantly below the currently authorized ROE of 9.50% and PGE's requested ROE of 9.75%. With the revenue requirement of the two plants included, PGE's ROE would be 4.38% without a rate increase. As discussed in testimony in PGE Exhibit 600, if PGE's ROE is underperforming the expected return of investments with equivalent risk, it would negatively impact PGE's ability to raise capital and fund operations needed to provide safe and reliable service to customers.

Q. Does PGE's 2025 revenue requirement include any costs associated with the Colstrip generating plant?

A. No. While we provide the above comparison for purposes of illustrating PGE's percentage increase inclusive of Colstrip recovery, pursuant to Commission Order No. 22-129 in UE 394, PGE has removed all identifiable costs for the Colstrip generating plant from base rates and included them within Schedule 146.[6] Consequently, no Colstrip operations and maintenance (O&M) or plant-related costs are included in PGE's 2025 revenue requirement request in this proceeding. Additionally, all Colstrip-related costs have been adjusted from PGE's actual results to provide for an apples-to-apples comparison.

Q. Are there any costs related to Wildfire Mitigation (WM) included in PGE's filing?

A. No. Similar to Colstrip, all WM-related costs have been removed from both actual and forecasted results, as these costs are recovered through a separate schedule.

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[6] Docket No. UE 394, Order No. 22-129 (April 25, 2022) at 3.

Q. Is PGE including any costs or benefits associated with the Clearwater Wind (Clearwater) project within this filing?

A. Yes. PGE's 2025 revenue requirement includes all costs and benefits related to Clearwater. Additionally, for purposes of providing an apples-to-apples comparison, both 2024 budget amounts and sales to consumers at current prices reflect the inclusion of Clearwater within base rates. Beginning January 1, 2025, PGE's Schedule 122 will be updated, such that no 2025 forecasted costs for Clearwater will be included within that schedule.

Q. Are there any costs or benefits associated with the Troutdale battery storage project (Troutdale) included in PGE's 2025 revenue requirement?

A. Troutdale, similar to PGE's Seaside battery project, is a 200-megawatt battery storage project being constructed within PGE's service territory, which will allow PGE to optimize the renewable power in its portfolio through a flexible, carbon-free, grid-balancing capacity resource. However, as Troutdale will be owned by NextEra Energy Resources through a 20-year Storage Capacity Agreement, all costs and benefits associated with this facility are included within UE 436, PGE's 2025 Net Variable Power Cost proceeding.

Q. Were actions taken to help limit the size of the requested increase?

A. Yes. To help mitigate the impact of prudent and necessary investments for continued provision of safe, affordable, and reliable service, we adjusted the revenue requirement to reflect the following reductions:

- Removing 100% of forecasted Officer incentive costs and 50% of all non-Officer forecasted incentive compensation costs, even though these incentives are a key part of all investor-owned utilities' total compensation and the entirety of PGE's incentive program benefits customers by allowing us to not only attract but also retain skilled employees.

- Removing 50% of all layers of Directors and Officers liability insurance costs, even though the entirety of these costs are standard and prudent business expenditures that allow PGE to attract and retain key talent and have been included in previous general rate cases.
- Removing approximately 50% of meals and entertainment costs based on 2023 actual meals and entertainment expenditures.
- Reducing PGE's labor expense by approximately $11.7 million to account for vacancies and/or unfilled positions.
- Reducing approximately $3.7 million in incurred property insurance costs from 2023 to 2025, due to the restructuring of our property insurance program to a "post-loss" funding model.

A. Summary of the Case

Q. Please summarize PGE's 2025 revenue requirement prior to inclusion of the major battery projects.

A. Table 1 below summarizes PGE's 2025 revenue requirement by major category and provides a comparison to the results of UE 416, including PGE's currently requested Clearwater revenue requirement as filed in UE 427. We also list the PGE testimony that addresses each specific cost category.

Table 1
Revenue Requirement Summary
($000s)

Rev Req Category	UE 416 Approved	UE 427 Filed	2025 Forecast	Exhibit	No.
Sales to Consumers	$ 2,705.5	$ (28.3)	$ 2,926.8	Rev Req	200
Other Revenue	49.8		46.3	Rev Req	200
Net Variable Power Costs	959.0	(92.6)	923.0	Rev Req	200
Production O&M	133.0	3.5	149.5	Production	500
Transmission O&M	20.9		22.1	T&D	400
Distribution O&M	186.2		209.2	T&D	400
Customer Service	105.8	0.1	102.7		
A&G	199.0	0.2	221.6	Corp. Support	300
Depr. & Amort.	420.4	16.8	476.9	Rev Req	200
Other Taxes	192.9	6.0	218.0	Rev Req	200
Income Taxes	105.6	7.7	126.3	Rev Req	200
Operating Income*	**$ 432.4**	**$ 30.3**	**$ 523.7**		
Return on Equity	9.5%	9.5%	9.75%**	ROE	600

** May not sum due to rounding*
***Calculated without UE 416 Revenue Requirement Adjustment*

Q. Do the above amounts reflect the adjustments to revenue requirement specified in Commission Order No. 23-386?

A. Yes. Pursuant to the second partial stipulation, adopted through Commission Order No. 23-386, PGE agreed to reflect a $4.25 million revenue requirement decrease in general rate cases through 2039. Additionally, pursuant to the fourth partial stipulation, adopted through Commission Order No. 23-386, PGE agreed to reflect a $213,000 revenue requirement decrease in general rate cases through 2028. As such, the sum of these two amounts is reflected as a downward adjustment to PGE's 2025 forecasted sales to consumers as shown in Table 1 above and in Column 3 of PGE Exhibit 201.

Q. Does PGE's 2025 test year forecast include any forecasted transaction costs for Amazon Pay payment options?

A. Yes. Pursuant to the second partial stipulation, adopted through Commission Order No. 23-386, PGE agreed to remove the cost of the program from its approved 2024 test year revenue requirement. However, parties agreed that PGE may propose recovery of amounts within future proceedings. As such, PGE has included $25,500 within this case for expected Amazon Pay transaction costs.

Q. Please describe Operating Income as used in Table 1 above.

A. Operating Income consists of a return to the providers of capital to PGE, both equity and debt. The costs of obtaining capital are discussed in PGE Exhibit 600.

Q. How did you develop the 2025 revenue requirement?

A. We developed the revenue requirement based on PGE's 2024 budget that reflects PGE's 2024 general rate case result as approved in Commission Order No. 23-386. The 2024 budget was escalated for inflation to 2025 and adjusted for known and measurable changes.

Q. What comparisons with the 2025 test year costs do you make in the testimonies generally?

A. We compare our forecast of 2025 test year costs to PGE's 2024 budget. The 2024 budget approximates the final UE 416 costs that are currently in PGE's retail rates, as approved by Commission Order No. 23-386. We perform these comparisons because this rate case test year is only one year beyond that of UE 416, which had a 2024 test year. As such the most accurate comparable basis from which to discuss changes expected in 2025 is PGE's 2024 budget.

Q. Did you perform a reconciliation of the 2024 budget to the 2024 general rate case (GRC) forecast?

A. Yes. We compared costs from the final stipulated revenue requirement in UE 416 with PGE's 2024 budget as listed in Table 2, below. In summary, the 2024 budget is within 0.64% of the aggregate final UE 416 costs.

Table 2
Compare 2024 GRC to 2024 Budget
($millions)

Revenue Requirement Category[1]	2024 GRC	2024 Budget[2]	Variance
Other Revenue[3]	$ (49,783)	$ (45,599)	$ 4,184
Operation & Maintenance			
Total Fixed O&M	343,608	346,430	2,822
Other O&M	304,911	304,303	(608)
Total Operation & Maintenance	648,519	650,733	2,214
Depreciation & Amortization	437,269	442,440	5,107
Other Taxes / Franchise Fees	198,592	194,969	(3,623)
Subtotal	635,861	637,408	1,547
Totals	**$ 1,234,597**	**$ 1,242,542**	**$ 7,945**
% Variance			**0.64%**

(1) Does not include net variable power costs or income taxes.
(2) Normalized to be comparable to the 2024 rate case, e.g., adjusted for SERP, MDCP, Incentives, Colstrip, etc., with the exception of Clearwater, which is included for both.
(3) GRC other revenue includes black box adjustments to PGE's revenue requirement.

Q. Why don't the individual lines match in Table 2 if the UE 416 amounts are the basis for the 2024 budget?

A. The specific line items do not equal for the following reasons:

- Several of the larger stipulated adjustments in UE 416 were applied to a single income statement line for regulatory purposes (e.g., adjustments to administrative and general costs). For budgeting purposes, PGE applied the adjustments to all different areas (e.g., distribution O&M).
- 2024 budget depreciation expense is higher than UE 416 depreciation expense, as UE 416 depreciation expense is based upon December 31, 2023 plant amounts, whereas 2024 budget depreciation expense includes 2023 and expected 2024 plant closings.
- Certain costs are based on actuary tables such as employee health care and retained losses. As new reports are received, PGE updates those budgets accordingly.

As noted above, however, in aggregate the 2024 budget is 0.64% higher than the 2024 GRC amount. This represents a variance of only $7.9 million compared to over $1,243 million in total costs.

Q. How did you escalate the 2024 budget to the 2025 test year?

A. We applied the following escalation rates to the 2024 budget:

- 4.00% for non-bargaining employee labor, effective February 1.
- [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] for bargaining employee labor, effective March 1.
- 3.36% for contract labor and outside services (cost elements [CE] 1502, 1602, 2200, and 2300), effective January 1.
- 1.02% for direct materials (CE 2101 and 2110), effective January 1.
- 2.58% for employee business expense (CE 2400 and 2701), effective January 1.

Q. What are the sources of these escalation rates?

A. For outside services, contract labor, direct materials, and employee business expenses, we used escalation rates from the Q3 2023 *IHS Markit*, Long-term Forecast. Wage escalation is based on the forecast of compensation costs as described in PGE Exhibit 300.

Q. Do you propose any changes to the uncollectibles rate in this proceeding?

A. No. PGE uses the UE 416 uncollectibles rate of 0.4%[7] for the 2025 test year. Applying this factor to total forecasted sales to consumers in 2025 produces an uncollectibles expense amount of approximately $11.7 million as shown in PGE Exhibit 201.

Q. What OPUC fee rate do you assume in this proceeding?

[7] As approved in Docket No. 416, Order No. 23-386 (Oct 30, 2023).

A. We assumed a 0.43% rate, grossed up for sales for resale.[8] However, just prior to filing this rate was increased to 0.45% of gross operating revenues, pursuant to Commission Order No. 24-054. As such, PGE will refresh this rate within a future revenue requirement update during the pendency of this proceeding.

Q. Did you adjust PGE's 2025 revenue requirement to reflect previous rate case decisions and other regulatory policies?

A. Yes. We made several regulatory adjustments, listed in Table 3 below.

Table 3
Regulatory Adjustments
($millions)

Category	O&M	Rate Base
Retail Services	$ (0.8)	$ (11.0)
Charitable Contributions	(2.4)	
State & Federal Lobbying	(1.4)	
MDCP	(3.4)	
SERP	(1.1)	
Image Advertising	(0.5)	
Total Adjustments*	**$ (9.6)**	**$ (11.0)**

** May not sum due to rounding*

Q. Please explain these regulatory adjustments.

A. The following is a brief summary of the adjustments:

- Retail services: removed the costs related to PGE's competitive retail operations.
- Charitable contributions and sponsorships: excluded the entire $2.4 million from cost of service.
- State and federal lobbying: excluded the entire $1.4 million from cost of service.
- Management Deferred Compensation Plan (MDCP): removed the entire $3.4 million from cost of service.

[8] This results in a 0.4834% rate.

- Supplemental Executive Retirement Plan (SERP): removed the entire $1.1 million from cost of service.
- Corporate image advertising: removed the entire $0.5 million from cost of service.

II. Other Revenue

Q. What is PGE's 2025 forecast of Other Revenue?

A. PGE forecasts 2025 Other Revenue of $46.3 million. This compares to actual 2024 budgeted Other Revenue of $45.6 million.

Q. What are the sources of Other Revenue?

A. The primary sources of Other Revenue are pole attachment rental revenue, third-party transmission revenue, late payment fees, and rent of electric property. PGE Exhibit 202 provides additional detail on the sources and amounts of Other Revenue.

Q. Did you make any adjustments related to Other Revenue for the 2025 test year?

A. Yes. We added approximately $0.49 million for fees collected for Green Power Administration and Green Tariff Administration to avoid double collecting these costs.

III. Depreciation

Q. What is the basis for the 2025 test year depreciation expense?

A. Normalization rules in the Internal Revenue Code, Section 168(i)(9) require consistency in the calculation of four items for ratemaking purposes. Two of the four items are tax expense and book depreciation expense. The other two items are in rate base: accumulated book depreciation and accumulated deferred income taxes (ADIT). Because PGE established its rate base as of December 31, 2024, we used depreciation through this date in the calculation of all four items.

Q. Does this depreciation accurately reflect the 2025 expense?

A. By itself, no. Because this depreciation will only reflect partial year depreciation for 2024 plant closings,[9] that depreciation will be less than full 2025 depreciation, which should reflect a full year of depreciation for those same assets. To adjust for this effect, PGE annualized the 2024 depreciation expense for 2024 plant closings and then reduced that amount to account for the annualized effect of declining depreciable base in prior vintages. In summary, the 2024 depreciation expense is annualized and adjusted so that PGE does not under or over collect depreciation expense relative to expected 2025 depreciation expense. Additionally, for purposes of determining accumulated depreciation in rate base, this same amount of depreciation expense is added to PGE's reserve. This treatment of depreciation expense and accumulated depreciation, matches PGE's usage of December 31, 2024 for establishing rate base, such that customers are paying for costs consistent with (i.e., matched with) the benefits

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[9] "Plant closings" refers to the accounting entries that move costs from Construction Work in Progress to Plant in Service when the assets become operational.

provided from PGE's investments. For simplicity, we refer to the test year depreciation as 2025 depreciation expense.

Q. What is PGE's estimate for 2025 depreciation expense?

A. We estimate $389.9 million in depreciation expense for 2025 excluding Constable and Seaside. PGE Exhibit 203 summarizes the 2025 depreciation expense by plant type and provides a comparison to 2024 budgeted amounts.

Q. Is PGE proposing any modifications to depreciation rates as part of this rate case?

A. Yes. PGE's most recent depreciation study was approved in Docket No. UM 2152 through Commission Order No. 21-463. PGE implemented the new depreciation rates effective May 9, 2022. While we have not filed a new depreciation study since UM 2152, and we are not proposing to modify the rates for any existing assets, PGE does propose a new depreciation rate for Constable and Seaside as these are the first large-scale battery projects to be included within PGE's rate base. We discuss this new rate further in Section VII below.

Q. How does PGE's 2025 depreciation expense forecast compare to 2024?

A. PGE's total base business forecasted depreciation for 2025 reflects a $28.1 million increase over 2024.

Q. What are the primary drivers for the increase?

A. The primary drivers of the increase in depreciation expense are:

- $17.0 million for transmission and distribution facilities.
- $6.6 million for general plant.
- $2.8 million for thermal plant.
- $1.8 million for wind, solar, and hydro plant.

Q. How does PGE account for Constable's and Seaside's depreciation expense?

A. Constable's and Seaside's depreciation expense of $8.3 million and $20.9 million respectively are included within the isolated revenue requirement for each project and discussed in more detail in Section VII below and in PGE Exhibit 500.

IV. Amortization

Q. What is amortization?

A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life. Amortization relates to intangible assets, such as computer software and regulatory assets. As with depreciation expense, the unamortized balance of the associated assets generally appears in rate base and earns a return at the allowed rate. Because amortization is also subject to Internal Revenue Service (IRS) tax normalization principles, we calculated the 2025 test year amortization expense similar to depreciation.

Q. Please summarize PGE's 2025 amortization expense.

A. PGE Exhibit 204 details the total 2025 amortization expense of $87.0 million, which we summarize in Table 4 below.

Table 4
Amortization Expense
($millions)

Category	2024 Budget	2025 Forecast
Software Amortization 3-10 years	$76.8	$82.1
Other Intangible Amortization	3.5	3.8
Trojan Decommissioning	1.9	1.9
Regulatory Credits		(0.5)
Retail Allocation		(0.2)
Total Amortization*	$82.2	$87.0

* May not sum due to rounding

Q. Did you make any adjustments to your amortization expense?

A. Yes. We applied a $0.5 million reduction to the 2025 amortization forecast in accordance with Commission Order No. 14-422 (Docket No. UE 283) to amortize the incentive-related $10 million rate base credit over 20 years.[10]

[10] Docket No. UE 283, Order 14-422 (Dec 4, 2014), Appendix B at 2.

Q. Please explain the amortization of software included in PGE's 2025 amortization expense.

A. Total software amortization is approximately $82.1 million. This cost relates to capitalized software, which is typically amortized over either a 3-year, 5-year, or 10-year period for larger software programs, such as PGE's customer information and meter data management systems.

Q. Why is software amortization approximately $5.2 million higher in 2025 compared to 2024?

A. The increase is primarily due to the replacement of PGE's Asset and Resource Management application. PGE's current application is obsolete and no longer supported.

Q. Please describe Other Intangible amortization.

A. Other Intangible amortization includes hydro relicensing amortization and miscellaneous other intangible plant amortization. For hydro relicensing, this represents the recognition of annual costs associated with non-construction projects that have closed to Plant in Service. Generally, these costs are amortized over the life of the new license.

Q. Does PGE recommend any changes to the current $1.9 million Trojan Nuclear Decommissioning Trust (Trojan NDT) collection rate?

A. No. PGE's Trojan NDT analysis continues to indicate that no change in the collection rate is needed. Based on the analysis and the considerable uncertainty associated with the spent nuclear fuel at the Trojan site, PGE proposes to maintain the annual accrual rate of $1.9 million. Our current Nuclear Regulatory Commission license for Trojan will expire in the first quarter of 2059.

V. Income Taxes and Taxes Other Than Income

A. Income Taxes

Q. What is PGE's 2025 estimate of income taxes?

A. PGE's 2025 test year forecast for income tax expense is $126.3 million. This compares to the 2024 utility income tax expense of $113.3 million based on prices approved by Commission Order No. 23-386 in UE 416, plus PGE's currently forecast 2024 revenue requirement for Clearwater, as filed in UE 427. PGE Exhibit 205 details the test year calculations of income tax expense and provides a comparison to previously authorized income tax assumptions.

Q. What method did you use to establish estimated income tax expense for the 2025 test year?

A. We use the "stand-alone" method to determine the test year income tax expense. This method uses as inputs only those costs and revenues included in our requested test year revenue requirement to determine the income tax expense for the test year. The Commission has traditionally used this approach to determine the income tax expense in test year price development. Further, because PGE's operations are nearly 100% regulated utility activity, this method also conforms to ORS 757.269, which specifies how income taxes are treated for developing prices.

Q. What income taxes does PGE pay?

A. PGE pays income taxes to the federal government, the states of Oregon, Montana, and California, and to local government entities such as the City of Portland, Multnomah County, and Metro.[11]

[11] Note that PGE pays an immaterial amount of income tax to other states where we have employees. As the costs are de minimis, we have not forecasted them or included them within our request.

Q. What marginal tax rates have you incorporated into your 2025 test year revenue requirement?

A. The federal marginal tax rate is 21.0%, the State of Oregon marginal tax rate is 7.60%, the State of California marginal tax rate is 8.84%, and the State of Montana marginal tax rate is 6.75%. We also include the City of Portland marginal tax rate of 2.60%.

Q. What is PGE's state composite tax rate for this filing?

A. PGE's state and local composite tax rate is 7.445%. The rate is a function of the marginal state tax rates and the respective apportionment factors of taxable income to different state and local jurisdictions.

Q. Did you include the Oregon Corporate Activities Tax (OCAT) in your 2025 test year revenue requirement?

A. Yes. We continue to include the OCAT in this GRC as a separate line item within the revenue requirement, which we include within Taxes Other Than Income.

Q. What is PGE's total composite tax rate for this filing?

A. PGE's total composite tax rate for this filing is 26.882%, which is the sum of the federal marginal tax rate and the state and local composite tax rate, less the effect of their interaction (i.e., local income taxes reduce state income taxes and state income taxes reduce federal income taxes), or as calculated in PGE Exhibit 201:

$$21.00\% + 7.445\% - (21.00\% * 7.445\%) = 26.882\%$$

Q. Did you exclude any tax rates from local jurisdictions from the calculation of the composite tax rate?

A. Yes. PGE collects Multnomah County Business income taxes (MCBIT) through supplemental Schedule 106 and Metro Supportive Housing Services Tax through supplemental

Schedule 103 to comply with Oregon Administrative Rule (OAR) 860-022-0045. Consequently, we do not include an estimate of either of these taxes as part of our revenue requirement.

Q. Did you include state and federal tax credits in your estimate of income tax expense for 2025?

A. Yes. PGE has applied the following items (treated similar to tax credits):

- A $10,000 state income tax credit, which specifies that PGE "will include a $10 thousand state tax credit … to account for the graduated tax rate in Oregon."[12]
- A net federal credit of approximately $7.8 million to reflect: 1.) the average rate assumption method (ARAM) of amortizing excess deferred federal income taxes (EDIT)[13] and 2.) the Cost of Removal (COR) component of EDIT previously included within ARAM, which the IRS has ruled should be treated separately.[14]

Q. Did you include any Production Tax Credits (PTCs) or Investment Tax credits (ITCs) in your estimate of income tax expense for 2025?

A. Consistent with the provisions of Oregon Senate Bill 1547, Section 18b, Federal PTCs are incorporated into PGE's net variable power costs (NVPC). Consequently, PGE's test year PTCs are reflected in its Annual Update Tariff (AUT) filing. PGE's large battery projects are eligible for Federal ITCs. However, we have not included a forecasted credit amount as part of this general rate case proceeding. We instead propose to monetize these credits and return them to customers through a separate amortization request. The specifics of PGE's proposal are discussed in greater detail within PGE Exhibit 500.

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[12] Docket No. UE 335, Order No. 18-464 (Dec 14, 2018) at page 5 of Appendix D, item 4.
[13] *Id.*, page 4 of Appendix D, item 2.f.
[14] To avoid a potential violation of IRS tax normalization requirements, PGE separated the COR component out in UE 416.

Q. Did you include a research and development (R&D) Income Tax Credit?

A. No. Because the R&D tax credit can vary significantly from year to year, we have established a deferral mechanism (Docket No. UM 1991) as specified by Commission Order No. 18-464.[15]

B. Taxes Other than Income

Q. What is PGE's 2025 estimate of Taxes Other Than Income?

A. As shown in PGE Exhibit 206, total Taxes Other Than Income are $218.0 million for 2025. This compares to a 2024 budget of $196.3 million. The primary cost changes from the 2024 budget to the 2025 test year are:

- Property Taxes: from $95.3 million to $102.8 million;
- Franchise Fees: from $62.7 million to $75.2 million;
- Payroll Taxes: from $22.5 million to $23.9 million, reflecting wage escalation; and
- OCAT: from $12.3 million to $13.0 million, reflecting increased revenues.

1. Property Taxes

Q. Please describe PGE's obligation to pay property taxes.

A. PGE owns property in three states: Oregon, Montana (Clearwater and Colstrip plant, and related transmission), and Washington (Tucannon River Wind Farm and Kelso-Beaver (KB) Pipeline for gas used at the Port Westward and Beaver plants). As a result, PGE is obligated to pay property taxes in each of these jurisdictions.

Q. How do these jurisdictions assess property taxes on PGE?

A. Rather than each individual county assessing property tax, Oregon, Montana, and Washington "centrally assess" PGE's property using a unit approach. This unit approach is required by

[15] *Id*. at 7-8.

state statutes because the properties are considered a single economic unit and system assets are thoroughly integrated in operation and construction. For example, a piece of wire cannot be valued without looking at its relationship to the entire unitary system. Each state uses a combination of three approaches to determine value: 1.) cost, 2.) income, and 3.) comparable sales. The result of each approach is considered and weighted by each respective state assessor in determining a correlated system value. The goal of this valuation process is to assess PGE's operating system as closely as possible to its real market value on January 1 of each year.

Q. Is PGE including property tax savings incentives related to major construction projects?

A. Yes. Similar to prior years, PGE has included tax savings related to Strategic Investment Program (SIP) property tax abatement agreements, which significantly reduces taxes for a 15-year period beginning in 2015 for Port Westward II, 2017 for Carty, and 2021 for Wheatridge.

Q. What is driving the increase in property taxes from 2024 to the 2025 test year?

A. The increase in property taxes from $95.3 million in 2024 to $102.8 million in 2025 is due primarily to an increase in forecasted net plant value that primarily impacts PGE's Oregon property tax. Additionally, the basis for estimating Clearwater property taxes in 2024 versus the basis required for 2025 is driving an increase to Montana property taxes.

2. Franchise Fees

Q. Why have franchise fees increased from 2024 to the 2025 test year?

A. As PGE has not updated the franchise fee rate since the rate of 2.565% was approved in UE 416, the increase to franchise fees is solely the function of PGE's requested revenue requirement.

<u>3. Payroll Taxes</u>

Q. How does PGE estimate payroll taxes?

A. PGE estimates payroll taxes by applying an approximate 9.4% payroll tax rate to total wages and salaries. We allocate a portion of payroll tax cost to plant consistent with the allocation of overall capitalized wages and salaries.

Q. Why have payroll taxes increased from 2024 to the 2025 test year?

A. Payroll taxes increase as wages and salaries grow between these years as described in PGE Exhibit 300.

VI. Rate Base

Q. What is PGE's test year rate base and what does it include?

A. As discussed in Section I, PGE established its rate base balances as of December 31, 2024, and forecasts the total balance to be approximately $7,347.4 million, excluding Constable and Seaside. PGE Exhibit 207 provides the details of this rate base, which includes PGE's investment in Plant in Service, net of Accumulated Depreciation, and ADIT. In addition, the rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's test year rate base compare to amounts approved in UE 416?

A. PGE Exhibit 208 shows that the rate base approved in UE 416 plus the rate base requested for Clearwater in UE 427 totals $6,615.7 million and that PGE's December 31, 2024 rate base reflects an increase of $731.7 million, excluding Constable and Seaside. The increase is primarily attributable to 1.) growth in distribution plant to address reliability and resiliency; 2.) major substation construction, including the Evergreen and Tonquin substations; and 3.) transmission and production construction. PGE Exhibits 400 and 500 provide more detail regarding some of the major construction projects, while PGE's work papers provide monthly plant closings in 2024 by funding project and depreciation group.

Q. Does PGE propose any updates to rate base during this proceeding?

A. Yes. Because the projects included within PGE's 2024 forecasted closings are in various stages of execution, we will provide parties to this proceeding one additional update of 2024 plant closings on or before May 1, 2024. Doing so will provide parties a more current view of expected closings for 2024, as projects will be further along in the execution stage, while also providing parties over a month[16] to review any adjustments from PGE's initially filed rate base before their opening testimony is due in the proceeding.

Q. Has PGE previously discussed its capital budgeting process including cost control measures built into the process and the concept of "stage-gating" projects?

A. Yes. In PGE's 2022 general rate case (UE 394), we described the annual capital budgeting process, including cost control measures employed with a rigorous bottom-up and top-down approach to managing a project's need, scope, budget and forecast. As part of this, PGE employs the stage-gating process to assess project readiness using four distinct project stages. PGE Exhibit 211 provides an excerpt of our testimony in UE 394 discussing this process. Ultimately, by providing parties an update prior to their opening testimony, projects slated for completion in 2024 will be further along within the stage-gating process, which provides parties a more accurate view of the projects and associated costs that are expected to close to plant and thus begin delivering system (and customer) benefits prior to January 1, 2025.

Q. Please describe how PGE forecasts accumulated depreciation included in rate base.

A. PGE's accumulated depreciation (i.e., reserve) is made up of the following amounts: 1.) the total accumulated amount of depreciation expense recorded on PGE's regulated books for all assets included in rate base up to December 31, 2023, plus 2.) an annualized (i.e., full twelve month) forecast of depreciation for all plant forecast to be placed into service between January 1, 2024 through December 31, 2024. Using this method, PGE's accumulated reserve is reflected on a consistent (i.e., apples-to-apples) basis with PGE's plant in-service amounts (a year-end basis), while providing customers the full-year depreciation benefit of 2024 plant additions regardless of their in-service date. Additionally, under this approach, which PGE

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[16] Based upon UE 416, in which Staff and Intervenor opening testimony was due June 13th.

has consistently used since its 2015 general rate case (UE 283), the costs customers pay are equal to the benefits they receive from PGE's capital investments.

Q. Does PGE propose a new lead-lag study to update working cash?

A. No. PGE uses the UE 416 working cash factor of 4.222%[17] for the 2025 test year. Applying this factor to total forecasted operating expenses in 2025 of $2,449.4 million produces the Working Cash total in rate base of approximately $103.4 million, which is shown in PGE Exhibit 201.

Q. Has PGE made any adjustment to rate base?

A. Yes. Consistent with our treatment in UE 416, PGE continues to include a downward adjustment to ADIT of approximately $18.4 million, thus reducing rate base by that amount. This amount represents the value of PTCs that would have been used had PGE's net income not been reduced due to the 2020 trading loss event. To determine this value, we calculated an adjusted net income for 2020 by removing the trading losses, and then completed our standard process for determining PTCs used.

Q. Has PGE included any PTC carryforward amount for 2024 within rate base?

A. Yes. While PGE is currently including a forecast of PTCs generated in 2024, less amounts forecast to be utilized, consistent with the outcome of UE 416, PGE recommends monetizing all PTCs generated in 2024 by Tucannon River, Wheatridge, Clearwater,[18] and eligible hydro facilities. PGE has filed a property sales application under Docket No. UP 426 reflecting this recommendation. As the full PTC value is received by customers through PGE's forecast of power costs, the property sales application would serve to collect from customers the difference between the full value of the PTC and the value received through a transaction with

[17] As approved in UE 416, Order No. 23-386 (Oct 30, 2023).
[18] A similar request was made in Docket No. UE 427 for Clearwater PTCs.

a third-party. Assuming PGE's property sales application is approved, PGE will remove the associated carryforward amounts from rate base within a subsequent update in this proceeding.

Q. Please discuss how you apply Allowance for Funds Used During Construction (AFUDC).

A. As capital projects are being constructed, their costs are recorded in construction work in progress (CWIP). These costs, however, are not included in rate base because the assets are not yet used and useful. AFUDC is, therefore, applied to the projects while they are in CWIP to represent the cost of money (i.e., debt and equity) used during construction. The CWIP costs are then capitalized as part of Plant in Service when the projects are placed in-service.

Q. How do you calculate AFUDC?

A. PGE uses a prescribed Federal Energy Regulatory Commission (FERC) formula to calculate the AFUDC rate. This rate is entered into PGE's accounting system, which calculates the monthly AFUDC amount to be recorded to projects in CWIP meeting applicable criteria. Examples of projects that are not applicable for AFUDC include: purchases for land without active construction, purchases of spare equipment, construction that starts and completes in the same month, cost of removal, and projects completed, cancelled, or suspended.

VII. Constable and Seaside Battery Storage

Q. What is the annual revenue PGE requires as a result of the addition of Constable and Seaside?

A. As shown in PGE Exhibit 201, columns 6 and 9, PGE requires an additional $17.3 million and $49.5 million annually for Constable's and Seaside's expected operating costs, net of dispatch benefits, as well as to provide a reasonable return on investment. These projects are discussed in more detail in PGE Exhibit 500.

Q. How did you estimate the operating costs of Constable and Seaside?

A. We estimated the operating costs on an annualized basis, reflecting costs for a full year of operations. Constable's total O&M costs of $1.2 million and depreciation expense of $8.3 million and Seaside's total O&M costs of $3.6 million and depreciation expense of $20.9 million reflect a full year's costs.

As Constable is currently projected to be placed into service by the end of December 2024, dispatch benefits included in the revenue requirement are forecast directly from PGE's MONET model. For Seaside we derived the dispatch benefits in the revenue requirement by taking the MONET forecasted benefit of approximately $10.6 million for Seaside's operations in 2025 and multiplying these benefits by the ratio of 12-month loads to the lesser amount of load during Seaside's respective operating period in 2025. This results in a reduction of $9.6 million in the Constable revenue requirement and a reduction of $20.7 million in the Seaside revenue requirement.

Q. How did you estimate the depreciation expense for these projects?

A. As these two batteries represent the first large-scale battery projects for PGE, we requested and received new depreciation parameters specific to these projects from Gannet Fleming

Valuation and Rate Consultants, LLC. The result of their project-specific study estimates an average depreciable life of approximately 20 years for both battery projects. These results are provided within the work papers for PGE Exhibit 500.

Q. How did you estimate the rate base for these projects?

A. The rate base of $146.4 million for Constable and $369.7 million for Seaside assumes gross plant amounts that close to plant as of these projects' in-service date and includes 12 months of accumulated depreciation, which matches depreciation expense and 12 months of accumulated deferred income taxes.

Q. Are ITCs included within the forecasted revenue requirements for Constable and Seaside?

A. No. In summary, PGE proposes to monetize the value of all ITCs received from these projects and return the net proceeds to customers over approximately 5 years through a separate amortization schedule. Under this proposal, described in PGE Exhibit 500, we currently estimate a year-one credit refund to customers of approximately $51.5 million. The final amount will ultimately be dependent on final plant in service amounts eligible for the ITC under Proposed Treasury Regulation § 1.48-9.

Q. Does PGE include property taxes associated with Constable and Seaside in their respective revenue requirement calculations?

A. Yes. Annualized property taxes for Constable amount to $2.4 million and annualized property taxes for Seaside amount to $6.6 million in 2025.

Q. When is PGE requesting prices effective to recover Constable and Seaside costs?

A. As stated above and explained in more detail in PGE Exhibit 900, we are requesting to track each project into prices effective with their in-service dates.[19] The annualized fixed costs of Constable and Seaside should only be minimally affected by the in-service date (e.g., monthly inflation on O&M) and are likely immaterial.

[19] Should Constable achieve in-service prior to January 2025, the price effective date for this project would be consistent with the January 1, 2025 price effective date requested for PGE's base rate request.

VIII. Unbundling

Q. Have you unbundled the 2025 revenue requirement pursuant to OAR 860-038-0200?

A. Yes. PGE Exhibit 210 summarizes the results of unbundling the integrated revenue requirement, as required by OAR 860-038-0200, into the required functional areas or revenue requirement categories. Table 5 below summarizes the base unbundled revenue requirement for 2025.

Table 5
Unbundled Revenue Requirement
($millions)

Production (including NVPC)	$ 1,630.5
Transmission	139.0
Distribution	957.6
Ancillary	7.8
Metering	2.4
Billing	48.1
Other Consumer Services	141.3
Total*	**$ 2,926.8**

** May not sum due to rounding*

The sum of the unbundled revenue requirement for these services equals the integrated revenue requirement as presented in PGE Exhibit 201, column 5.

The total unbundled revenue requirement for Constable and Seaside is presented in Exhibits 212 and 213.

Q. How did you develop the revenue requirement after unbundling costs and rate base?

A. We used traditional revenue requirement methodology – recovery of cost plus a return on rate base – to calculate the revenue requirement for each unbundled service in accordance with OAR 860-038-0200(9)(d). This is consistent with PGE's approach in past rate filings.

Q. How did you unbundle PGE's 2025 expenses and Other Revenue?

A. We unbundled expenses and Other Revenue by analyzing each account within those categories. First, we determined which accounts could be directly assigned to one of the functional categories listed in Table 5 above. Second, we evaluated those accounts that could not be clearly assigned to determine a basis for allocation.

Q. Were most of the expense and Other Revenue accounts assigned or allocated?

A. The majority of accounts have a direct relationship with a single functional area, and we assigned these accounts based on OAR 860-038-0200(9)(b)(A) through (E). The largest category of allocated expenses is A&G, which we allocated to the functional areas based on an O&M labor allocator. Other costs, such as property taxes and payroll taxes, relate to factors such as net plant or labor. Consequently, we allocated these costs in accordance with OAR 860-038-0200(9)(c)(B)(i) through (ii). For other expenses, such as depreciation and amortization, we "functionalized in the same manner as the respective plant accounts" in accordance with OAR 860-038-0200(9)(c)(A).

Q. Did you allocate any expense or Other Revenue to retail or non-utility?

A. Yes, for retail and no for non-utility. First, we allocate costs to retail activities based on assets allocated to retail. Second, while we forecast labor costs in non-utility, "below-the-line" accounts, these accounts already receive allocations for corporate governance (i.e., A&G/Support costs) and service providers (i.e., Facilities, Information Technology, and Print/Mail Services). Therefore, unbundling A&G (or other support costs) to non-utility accounts would apply these costs twice.

Q. How did you unbundle rate base?

A. There are two categories of rate base that we evaluated for unbundling: 1.) Plant in Service with associated Depreciation Reserve and ADIT; and 2.) other rate base. For Plant in Service, we assigned most assets and their associated contra accounts in accordance with OAR 860-038-0200(9)(a)(A) through (F). These assets clearly relate to specific functional areas (e.g., thermal and hydro-generating plants; transmission towers and conductors; distribution poles, conductors, substations, and transformers). Some general and intangible plant was directly assigned, but the majority of these categories consist of many smaller assets less clearly attributable to a functional area, so we allocated them based on an O&M labor allocator.

Q. How did you unbundle other rate base?

A. We assigned or allocated other rate base using the criteria established in OAR 860-038-0200(9)(a)(G). Specifically, we evaluated other rate base on an account-by-account basis and directly assigned where applicable (e.g., fuel inventories are assigned to Production). For other categories, we allocated costs on an appropriate basis (e.g., deferred credits related to post-retirement medical and life insurance are allocated based on O&M labor).

Q. Did you assign franchise fees to the distribution function?

A. Yes. Pursuant to OAR 860-038-0200(9)(c)(B)(i)(IV), PGE assigned franchise fees directly to the distribution function. We also assigned write-offs for uncollectibles directly to the distribution function.

IX. Qualifications

Q. Mr. Batzler, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Radio and Television from San Francisco State University in 1997 and a Master of Business Administration degree from Marylhurst University in 2011. I have been employed at PGE since 2006, working in various departments including Meter Reading and Human Resources. I have worked in the Rates and Regulatory Affairs department since 2012.

Q. Ms. Ferchland, please state your educational background and experience.

A. I received a Bachelor of Science in Electrical Engineering and a Master of Business Administration both from the University of Denver and a Post-Baccalaureate in Accounting from Portland State University. I joined PGE in 2015 as an Investor Relations Analyst and transitioned to the Principal Treasury Analyst role in 2017 where I worked with PGE's revolving credit facility, debt issuances, and annual rating agency presentations. I became the Manager of Revenue Requirement within Rates and Regulatory Affairs in November 2019, and I became the Senior Manager of Revenue Requirement in October 2023.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	Description
201	2025 Results of Operations Summary
202	Summary of Other Revenue
203	Summary of Depreciation Expense
204	Summary of Amortization Expense
205	Summary of Income Taxes
206	Summary of Taxes Other Than Income
207	Summary of Rate Base
208	Rate Base Comparison
209	Production Tax Credits
210	2025 Unbundled Results of Operations Summary
211	PGE's Capital Cost Management Practices Excerpt from UE 394, PGE Exhibit 1800
212	Constable Unbundled Results of Operations Summary
213	Seaside Unbundled Results of Operations Summary

UE 435
Exhibit 201
Increase in Base Rates Needed for Reasonable Return
Scaled (Thousands)

	Base Rate	Change for Resonable Return (with NVPC)	UE 416 Adjustment	2025 Load Adjusted NVPC Change	NVPC Adjusted Results after Change for Reasonable Return
	(1)	(2)	(3)	(4)	(5)
					1+2+3-4
					6.34%
Sales to Consumers all Schedules (calendar)	3,030,517				
Other Supplementals (calendar)	259,546				
Schedule 146 Sales to Consumer (calendar)	72,207				72,207
Sales to Consumers less NVPC Impact					2,874,568
Load Adjusted NVPC Impact				52,262	52,262
Base Sales to Consumers (Rev. Req.)	2,698,764	232,529	(4,463)		2,926,830
Other Revenue Detail	46,271	-	-		46,271
Total Operating Revenue	2,745,035	232,529	(4,463)		2,973,102
Operation & Maintenance					
Net Variable Power Cost	922,992	-	-		922,992
Production O&M	118,426	-	-		118,426
Power Operations	31,066	-	-		31,066
Trojan O&M	64	-	-		64
Transmission O&M	22,099	-	-		22,099
Distribution O&M	209,199	-	-		209,199
Operations O&M	380,854				380,854
Customer Accounts	63,755	-	-		63,755
Customer Service	27,187	-	-		27,187
Uncollectibles Expense	10,795	930	-		11,725
OPUC Fees	13,046	1,124	-		14,170
A&G, Ins/Bene., & Gen. Plant	207,450	-	-		207,450
Support O&M	322,233	2,054			324,287
Total Operating & Maintenance	1,626,079	2,054	-		1,628,133
Depreciation	389,862	-	-		389,862
Amortization	87,049	-	-		87,049
Property Tax	102,796	-	-		102,796
Payroll Tax	23,909	-	-		23,909
Other Taxes	3,112	-	-		3,112
Oregon CAT	12,969	-	-		12,969
Franchise Fees	69,226	5,965	-		75,191
Utility Income Tax	66,004	60,334	-		126,338
Total Operating Expenses & TOTI	2,381,006	68,353			2,449,358
Utility Operating Income	364,030	164,177	(4,463)		523,743

UE 435
Exhibit 201
Increase in Base Rates Needed for Reasonable Return
Scaled (Thousands)

	Base Rate	Change for Resonable Return (with NVPC)	UE 416 Adjustment	2025 Load Adjusted NVPC Change	NVPC Adjusted Results after Change for Reasonable Return
Rate of Return w-o UE 416 Adj	4.956%				7.189%
Weighted Cost of Debt	2.314%	2.314%			2.314%
Weighted Cost of Preferred					
Equity Share of Cap Structure	50.000%	50.000%	50.000%		50.000%
Return on Equity	5.285%				9.750%
Rate Base					
Gross Plant	13,651,008	-	-		13,651,008
Accum. Deprec. / Amort	(5,781,118)	-	-		(5,781,118)
Accum. Def Tax	(719,665)	-	-		(719,665)
Net Utility Plant	7,150,225				7,150,225
Operating Materials & Fuel	103,783	-	-		103,783
Misc. Deferred Credits	(39,249)	-	-		(39,249)
Misc. Deferred Debits	29,255	-	-		29,255
Working Cash	100,524	2,886	-		103,410
Total Rate Base	7,344,539	2,886			7,347,424
Income Tax Calculations					
Book Revenues	2,745,035	232,529	(4,463)		2,977,565
Book Expenses	2,315,002	8,019	-		2,323,020
Interest Expense	169,953	67	-		170,019
Permanent / Flow-Through M Differences	(14,546)	-	-		(14,546)
Temporary Sch M Differences	161,013	-	-		161,013
State Taxable Income	113,614	224,444	(4,463)		338,058
State Income Tax	8,449	16,710	-		25,158
Federal Taxable Income	105,165	207,734	(4,463)		312,899
Federal Tax	22,085	43,624	-		65,709
Deferred Taxes	43,283	-	-		43,283
Excess Deferred Income Tax Reversal (ARAM)	(10,121)	-	-		(10,121)
Excess Cost of Removal (COR) Reversal	2,309	-	-		2,309
Total Income Tax	66,004	60,334	-		126,338

UE 435
Exhibit 201
Increase in Base Rates Needed for Rea
Scaled (Thousands)

	Constable Change for Resonable Return	January 1, 2025 NVPC Adjusted Base Business Results	**January 1, 2025 Total Customer Price Increase***	Seaside Change for Resonable Return	**Total 2025 Customer Price Impact All Schedules****
	(6)	(7)	(8)	(9)	(10)
			5+6		8+9
		7.29%	7.42%		7.32%
Sales to Consumers all Schedules (calendar)			3,255,365		3,252,381
Other Supplementals (calendar)			239,002		186,565
Schedule 146 Sales to Consumer (calendar)		72,207	72,207		72,207
Sales to Consumers less NVPC Impact		2,900,721			
Load Adjusted NVPC Impact		43,434			
Base Sales to Consumers (Rev. Req.)	17,325	2,944,155	2,944,155	49,453	2,993,608
Other Revenue Detail	-		46,271	-	46,271
Total Operating Revenue	17,325		2,990,426	49,453	3,039,879
Operation & Maintenance					
Net Variable Power Cost	(9,558)		913,434	(20,657)	892,777
Production O&M	633		119,059	2,464	121,523
Power Operations			31,066		31,066
Trojan O&M	-		64	-	64
Transmission O&M	350		22,449	500	22,949
Distribution O&M	-		209,199	-	209,199
Operations O&M	983		381,837	2,964	384,801
Customer Accounts			63,755		63,755
Customer Service	-		27,187	-	27,187
Uncollectibles Expense	69		11,794	198	11,992
OPUC Fees	84		14,253	239	14,492
A&G, Ins/Bene., & Gen. Plant	74		207,524	182	207,706
Support O&M	227		324,514	619	325,133
Total Operating & Maintenance	(8,348)		1,619,785	(17,074)	1,602,711
Depreciation	8,269		398,131	20,850	418,982
Amortization	-		87,049	-	87,049
Property Tax	2,353		105,149	6,563	111,712
Payroll Tax	-		23,909	-	23,909
Other Taxes	-		3,112	-	3,112
Oregon CAT			12,969		12,969
Franchise Fees	444		75,635	1,269	76,904
Utility Income Tax	4,078		130,416	11,269	141,685
Total Operating Expenses & TOTI	6,797		2,456,155	22,876	2,479,032
Utility Operating Income	10,528		534,271	26,577	560,848

UE 435
Exhibit 201
Increase in Base Rates Needed for Rea
Scaled (Thousands)

	Constable Change for Resonable Return	January 1, 2025 NVPC Adjusted Base Business Results	**January 1, 2025 Total Customer Price Increase***	Seaside Change for Resonable Return	**Total 2025 Customer Price Impact All Schedules****
Rate of Return w-o UE 416 Adj	7.189%		7.189%	7.189%	7.189%
Weighted Cost of Debt	2.314%		2.314%	2.314%	2.314%
Weighted Cost of Preferred					
Equity Share of Cap Structure	50.000%		50.000%	50.000%	50.000%
Return on Equity	9.750%		9.750%	9.750%	9.750%
Rate Base					
Gross Plant	157,058		13,808,066	396,000	14,204,066
Accum. Deprec. / Amort	(8,269)		(5,789,387)	(20,850)	(5,810,238)
Accum. Def Tax	(2,636)		(722,301)	(6,430)	(728,731)
Net Utility Plant	146,152		7,296,378	368,720	7,665,097
Operating Materials & Fuel	-		103,783	-	103,783
Misc. Deferred Credits	-		(39,249)	-	(39,249)
Misc. Deferred Debits	-		29,255	-	29,255
Working Cash	287		103,697	966	104,663
Total Rate Base	146,439		7,493,864	369,686	7,863,549
Income Tax Calculations					
Book Revenues	17,325		2,994,889	49,453	3,044,342
Book Expenses	2,719		2,325,739	11,608	2,337,347
Interest Expense	3,389		173,408	8,555	181,963
Permanent / Flow-Through M Differences	(3,954)		(18,499)	(12,629)	(31,128)
Temporary Sch M Differences	(20,693)		140,320	(50,473)	89,846
State Taxable Income	35,864		373,922	92,393	466,315
State Income Tax	2,670		27,828	6,879	34,707
Federal Taxable Income	33,194		346,094	85,514	431,608
Federal Tax	6,971		72,680	17,958	90,638
Deferred Taxes	(5,563)		37,720	(13,568)	24,152
Excess Deferred Income Tax Reversal (ARAM)	-		(10,121)	-	(10,121)
Excess Cost of Removal (COR) Reversal	-		2,309	-	2,309
Total Income Tax	4,078		130,416	11,269	141,685

* Reflects forecasted base business, NVPC, Constable, and all known changes to supplemental schedules effective January 1, 2025

** Reflects forecasted base business, NVPC, Constable, Seaside, ITC amortization, and all known changes to supplemental schedules effective June 2025

PGE
UE 435
Exhibit 201
Capital Structure / Revenue Sensitive Costs
Not Scaled

Line No.	Rates	Dec - 2025
1	% R&D per UE 335	0.9097%
2	California State Income Tax - Appor	4.1012%
3	California State Income Tax - Rate	8.8400%
4	California State Income Tax - Weighted	0.3625%
5	Common Equity - Cost	9.7500%
6	Common Equity - Share	50.0000%
7	Common Equity - Weighted	4.8750%
8	Composite Tax Rate	26.8815%
9	Factor per OAR	0.1250%
10	Fed Tax	21.0000%
11	Federal Tax @ 21.000%	18.7663%
12	Federal Taxable Inc.	89.3633%
13	Franchise Fees	2.5651%
14	Gross-Up Factor	1.3676
15	Long-Term Debt - Cost	4.628%
16	Long-Term Debt - Share	50.000%
17	Long-Term Debt - Weighted	2.314%
18	Montana State Income Tax - Appor	2.3960%
19	Montana State Income Tax - Rate	6.7500%
20	Montana State Income Tax - Weighted	0.1617%
21	Net To Gross Factor	141.6491%
22	O&M Uncollectibles	0.4000%
23	OPUC Fees	0.4834%
24	Oregon Benefit of Local Tax deduction	(0.0020%)
25	Oregon State Income Tax - Appor	90.7385%
26	Oregon State Income Tax - Rate	7.6000%
27	Oregon State Income Tax - Weighted	6.8961%
28	Portland Local Income Tax - Appor	1.0236%
29	Portland Local Income Tax - Rate	2.6000%
30	Portland Local Income Tax - Weighted Plus Benefit	0.0246%
31	Portland Local Income Tax - Weighted Pre Benefit	(0.0266%)
32	Revenues	100.0000%
33	RSC Gross-Up Factor	1.0357
34	State and Local Tax @ Present Rate	7.1882%
35	State and Local Tax Rate - Weighted	7.4450%
36	State Taxable Income	96.5515%
37	Tax Shield	(1.5634%)
38	Total Income Taxes	25.9545%

PGE
UE 435
Exhibit 201
Capital Structure / Revenue Sensitive Costs
Not Scaled

Line No.	Rates	Dec - 2025
39	Total Rev. Sensitive Costs	29.4030%
40	Utility Operating Income	70.5970%
41	Working Cash Factor	4.2219%
42	Capital Structure Total	7.189%

PGE
UE 435
Exhibit 202
Other Revenue Detail
Not Scaled

Line No.	Account	a-Dec - 2021	a-Dec - 2022	a-Dec - 2023
1	4470003: SalesfrResale-IntertiePGEtoPGE	-	-	-
2	4500001: Forefeited Discounts	(1,384,370)	(2,462,939)	(6,862,843)
3	4510001: Miscellaneous Service Revenues	(629,537)	(874,209)	(1,541,350)
4	4530001: Sales of Water & Water Power	6,587	25,917	28,980
5	4540001: Rent From Electric Property	(1,535,450)	(1,457,150)	(1,446,445)
6	4540002: RentFrElecProperty-Joint Pole	(14,224,820)	(14,254,253)	(17,521,557)
7	4560001: Other Electric Revenues	(6,595,414)	(6,174,115)	(3,246,666)
8	4560002: OthElecRev-RegulatoryDeferRev	2,374,347	1,962,199	(3,723,174)
9	4560003: OthElecRev-FishWildlifeRecrOps	(12,590)	(14,115)	(29)
10	4560005: OthElecRev-Utility Non-Kwh	(32,509)	(25,254)	(11,623)
11	4560012: OthElecRev-Steam Sales	(2,562,812)	(5,059,402)	(4,365,520)
12	4561001: TransRevOthers-Non-Intertie	(3,826,701)	(82,263)	(41,111)
13	4561002: TransRevOthers-Intertie	(7,375,517)	(64,794)	-
14	4561004: Trans Network Services	-	(5,518,169)	(4,964,691)
15	4561005: Trans Long Term Firm	-	(11,377,573)	(9,863,012)
16	4561006: Trans Short Term Firm	-	(374)	(538,996)
17	4561007: Trans Short Term Non-Firm	-	(662,425)	(1,518,790)
18	4561008: Trans Other Services	-	3,883,829	4,371,674
19	5660002: TransOp-MiscExp-IntertieWhePGE	-	-	-
20	Total	(35,798,788)	(42,155,091)	(51,245,153)

PGE
UE 435
Exhibit 202
Other Revenue Detail
Not Scaled

Line No.	Account	Dec - 2024	Dec - 2025
1	4470003: SalesfrResale-IntertiePGEtoPGE	-	-
2	4500001: Forefeited Discounts	(7,195,860)	(7,156,026)
3	4510001: Miscellaneous Service Revenues	(1,148,858)	(1,637,808)
4	4530001: Sales of Water & Water Power	-	-
5	4540001: Rent From Electric Property	(1,323,341)	(1,323,341)
6	4540002: RentFrElecProperty-Joint Pole	(14,601,533)	(14,601,533)
7	4560001: Other Electric Revenues	(1,346,051)	(1,346,051)
8	4560002: OthElecRev-RegulatoryDeferRev	(4,748,975)	(4,972,852)
9	4560003: OthElecRev-FishWildlifeRecrOps	(12,110)	(11,522)
10	4560005: OthElecRev-Utility Non-Kwh	-	-
11	4560012: OthElecRev-Steam Sales	(2,300,000)	(2,300,000)
12	4561001: TransRevOthers-Non-Intertie	-	-
13	4561002: TransRevOthers-Intertie	-	-
14	4561004: Trans Network Services	-	-
15	4561005: Trans Long Term Firm	-	-
16	4561006: Trans Short Term Firm	-	-
17	4561007: Trans Short Term Non-Firm	-	-
18	4561008: Trans Other Services	(12,922,260)	(12,922,260)
19	5660002: TransOp-MiscExp-IntertieWhePGE	-	-
20	Total	(45,598,988)	(46,271,392)

PGE
UE 435
Exhibit 203
Depreciation Detail
Scaled (Thousands)

Line No.	Property Group	Dec - 2021	Dec - 2022	Dec - 2023
		(1)	(2)	(3)
1	Beaver	7,177	7,660	9,275
2	Biglow Canyon	29,019	29,801	29,539
3	Carty	12,292	12,286	12,017
4	Clearwater			
5	Coyote Springs	4,578	4,432	4,540
6	DSG	340	352	347
7	Port Westward	7,745	7,564	7,337
8	Port Westward 2	7,225	8,122	7,754
9	Solar	51	36	79
10	Tucannon	14,315	14,900	15,028
11	Wheatridge	5,525	5,490	5,168
12	Hydro	22,417	20,705	27,970
13	Transmission	21,067	22,505	24,770
14	Distribution	132,840	130,059	137,300
15	General Plant	41,480	48,884	48,391
16	**Total**	306,072	312,795	329,517
18	Retail Adjustment	-	-	-
19	**Adjusted Total**	306,072	312,795	329,517

Need to reflect WM removals

PGE
UE 435
Exhibit 203
Depreciation Detail
Scaled (Thousands)

Line No.	Property Group	Dec - 2024	Dec - 2025
		(4)	(5)
1	Beaver	11,603	12,991
2	Biglow Canyon	29,694	30,266
3	Carty	12,064	11,945
4	Clearwater	16,538	16,514
5	Coyote Springs	4,290	4,302
6	DSG	721	1,444
7	Port Westward	7,594	8,074
8	Port Westward 2	7,592	7,921
9	Solar	77	80
10	Tucannon	14,827	15,058
11	Wheatridge	4,976	4,975
12	Hydro	24,063	25,101
13	Transmission	27,094	32,233
14	Distribution	151,967	163,808
15	General Plant	48,701	55,271
16	**Total**	361,801	389,984
18	Retail Adjustment	-	(122)
19	**Adjusted Total**	361,801	389,862

Need to reflect WM removals

PGE
UE 435
Exhibit 204
Amortization Detail
Scaled (Thousands)

Line No.	Item	FERC Account	Dec - 2021	Dec - 2022
			(1)	(2)
1	Software Amortization (Intangible)	404	54,204	56,615
2	Other Intangible Plant (Includes Hydro Relicensing)	404	3,778	3,486
3	Amort Of UnrecvPlt-Troj Decomm	FERC_4070	-	-
4	Amort Of UnrecvPlt-Troj Decomm	FERC_4070	1,900	1,900
5	Regulatory Credits - Incentive Adjustment	FERC_4074		
6	Regulatory Credits - Sunway 3	FERC_4074	(45)	(45)
7	Allocated to Retail		-	-
8		**Total**	59,836	61,955

PGE
UE 435
Exhibit 204
Amortization Detail
Scaled (Thousands)

Line No.	Item	FERC Account	Dec - 2023	Dec - 2024
			(3)	(4)
1	Software Amortization (Intangible)	404	62,312	76,821
2	Other Intangible Plant (Includes Hydro Relicensing)	404	3,552	3,542
3	Amort Of UnrecvPlt-Troj Decomm	FERC_4070	475	1,900
4	Amort Of UnrecvPlt-Troj Decomm	FERC_4070	1,425	-
5	Regulatory Credits - Incentive Adjustment	FERC_4074		
6	Regulatory Credits - Sunway 3	FERC_4074	(45)	(45)
7	Allocated to Retail		-	-
8		**Total**	67,719	82,217

PGE
UE 435
Exhibit 204
Amortization Detail
Scaled (Thousands)

Line No.	Item	FERC Account	Dec - 2025
			(5)
1	Software Amortization (Intangible)	404	82,084
2	Other Intangible Plant (Includes Hydro Relicensing)	404	3,792
3	Amort Of UnrecvPlt-Troj Decomm	FERC_4070	1,900
4	Amort Of UnrecvPlt-Troj Decomm	FERC_4070	-
5	Regulatory Credits - Incentive Adjustment	FERC_4074	(500)
6	Regulatory Credits - Sunway 3	FERC_4074	(45)
7	Allocated to Retail		(181)
8		**Total**	87,049

PGE
UE 435
Exhibit 205
Income Tax Summary
Scaled (Thousands)

Line No.	Line	UE 416 2024 Test Year	UE 427 Clearwater RAAC	Subtotal UE 416 + UE 427	
1	Book Revenues (Including UE 416 Adjustment)	2,755,256	(28,334)	2,726,922	
2	Book Expenses (including Depreciation)	2,217,294	(66,236)	2,151,057	
3	Interest Deduction	138,656	9,701	148,357	
4	Book Taxable Income	399,307	28,201	427,508	
5	Production Deduction				
6	Permanent / Flow-Through Sch. M	(17,616)	(166)	(17,782)	
7	Temporary/Deferred Sch. M	42,576	(1,505)	41,071	
8	Taxable Income	374,347	29,872	404,219	
9					
10	Current State Taxes	28,308	2,259	30,567	
11	State Tax Credits	(10)			
12	Net State Income Tax	28,298	2,259	30,567	
13					
14	Federal Taxable Income	346,049	27,613	373,662	
15					
16	Current Federal Taxes	72,670	5,799	78,469	
17					
18	Federal Tax Credits				
19	Excess ADIT/COR Reversal	(6,843)		(6,843)	
20	Deferred Taxes	11,484	(406)	11,079	
21					
22	Total Income Tax	105,610	7,652	113,272	
23	Effective Tax Rate	26.45%	27.13%	26.50%	
24	Regulated Net Income	293,697	20,549	314,236	

Change in Taxes

<u>Analysis of Tax Change:</u>

Effective Tax Rate Change
Book Taxable Income (Last Rate Case + RAAC)
increase in Taxes Due to Higher Effective Rate

Change in Book Taxable Income (Current vs Last Rate Case)
2025 Effective Tax Rate
Increase in Taxes Due to Higher Book Taxable Income

PGE
UE 435
Exhibit 205
Income Tax Summary
Scaled (Thousands)

Line No.	Line	UE 416 2024 Test Year	UE 427 Clearwater RAAC	Subtotal UE 416 + UE 427	
	Sum of Tax Impacts				

PGE
UE 435
Exhibit 205
Income Tax Summary
Scaled (Thousands)

Line No.	Line	Proposed: Proposed
1	Book Revenues (Including UE 416 Adjustment)	2,973,102
2	Book Expenses (including Depreciation)	2,323,020
3	Interest Deduction	170,019
4	Book Taxable Income	480,062
5	Production Deduction	
6	Permanent / Flow-Through Sch. M	(14,546)
7	Temporary/Deferred Sch. M	161,013
8	Taxable Income	333,595
9		
10	Current State Taxes	25,168
11	State Tax Credits	(10)
12	Net State Income Tax	25,158
13		
14	Federal Taxable Income	308,436
15		
16	Current Federal Taxes	65,709
17		
18	Federal Tax Credits	
19	Excess ADIT/COR Reversal	(7,812)
20	Deferred Taxes	43,283
21		
22	Total Income Tax	126,338
23	Effective Tax Rate	26.07%
24	Regulated Net Income	353,724
	Change in Taxes	20,728
	Analysis of Tax Change:	
	Effective Tax Rate Change	-0.42%
	Book Taxable Income (Last Rate Case + RAAC)	427,508
	increase in Taxes Due to Higher Effective Rate	(1,801)
	Change in Book Taxable Income (Current vs Last Rate Case)	52,554
	2025 Effective Tax Rate	26.07%
	Increase in Taxes Due to Higher Book Taxable Income	13,703

PGE
UE 435
Exhibit 205
Income Tax Summary
Scaled (Thousands)

Line No.	Line	Proposed: Proposed
	Sum of Tax Impacts	11,903

PGE
UE 435
Exhibit 206
Taxes Other Than Income
Not Scaled

Line No.	Item	FERC	Account	Dec - 2021
1	Payroll Taxes	FERC_4081	4081004: Payroll Taxes - FICA	27,194,747
2	Payroll Taxes	FERC_4081	4081005: Payroll Taxes - Fed Unemploy	139,699
3	Payroll Taxes	FERC_4081	4081006: Payroll Taxes - Trimet	2,114,912
4	Payroll Taxes	FERC_4081	4081007: Payroll Taxes - State Umemploy	1,953,563
5	Payroll Taxes	FERC_4081	4081008: Payroll Taxes - Worker's Comp	279,369
6	Payroll Taxes	FERC_4081	4081009: AllocCredit - Payroll Tax	(15,059,038)
7	Property Taxes - Oregon	FERC_4081	4081001: TaxOthThan IncTax-PropTax-Oreg	68,983,883
8	Property Taxes - Washington	FERC_4081	4081002: TaxOthThan IncTax-PropTax-Wash	2,068,163
9	Property Taxes - Montana	FERC_4081	4081003: TaxOthThan IncTax-PropTax-MT	703,523
10	Franchise Fees	FERC_4081	4081010: TaxOthThanIncTax-FranFeePort	15,329,433
11	Franchise Fees	FERC_4081	4081011: TaxOthThanIncTax-FranFeeOthCit	32,942,514
12	Foreign Insurance Excise Tax	FERC_4081	4081012: TaxOthThanIncTx-ForInsrExcisTx	70,826
13	Misc. Tax & Lic Fees - Oregon	FERC_4081	4081013: TaxOthThanIncTx-MiscTax&Lic-OR	2,377,602
14	Misc. Tax & Lic Fees - Montana	FERC_4081	4081014: TaxOthThanIncTx-MiscTax&Lic-MT	287,941
15	Oregon CAT	40910	4091230: OR Corp Activity Tax-Utility	8,328,745
				147,715,883

PGE
UE 435
Exhibit 206
Taxes Other Than Income
Not Scaled

Line No.	Item	FERC	Account	Dec - 2022
1	Payroll Taxes	FERC_4081	4081004: Payroll Taxes - FICA	27,833,943
2	Payroll Taxes	FERC_4081	4081005: Payroll Taxes - Fed Unemploy	139,841
3	Payroll Taxes	FERC_4081	4081006: Payroll Taxes - Trimet	2,334,323
4	Payroll Taxes	FERC_4081	4081007: Payroll Taxes - State Umemploy	3,433,917
5	Payroll Taxes	FERC_4081	4081008: Payroll Taxes - Worker's Comp	330,051
6	Payroll Taxes	FERC_4081	4081009: AllocCredit - Payroll Tax	(16,110,505)
7	Property Taxes - Oregon	FERC_4081	4081001: TaxOthThan IncTax-PropTax-Oreg	73,151,107
8	Property Taxes - Washington	FERC_4081	4081002: TaxOthThan IncTax-PropTax-Wash	2,427,170
9	Property Taxes - Montana	FERC_4081	4081003: TaxOthThan IncTax-PropTax-MT	667,579
10	Franchise Fees	FERC_4081	4081010: TaxOthThanIncTax-FranFeePort	16,244,806
11	Franchise Fees	FERC_4081	4081011: TaxOthThanIncTax-FranFeeOthCit	36,314,842
12	Foreign Insurance Excise Tax	FERC_4081	4081012: TaxOthThanIncTx-ForInsrExcisTx	6,093
13	Misc. Tax & Lic Fees - Oregon	FERC_4081	4081013: TaxOthThanIncTx-MiscTax&Lic-OR	2,535,464
14	Misc. Tax & Lic Fees - Montana	FERC_4081	4081014: TaxOthThanIncTx-MiscTax&Lic-MT	439,967
15	Oregon CAT	4091O	4091230: OR Corp Activity Tax-Utility	8,727,970
				158,476,568

PGE
UE 435
Exhibit 206
Taxes Other Than Income
Not Scaled

Line No.	Item	FERC	Account	Dec - 2023
1	Payroll Taxes	FERC_4081	4081004: Payroll Taxes - FICA	29,331,636
2	Payroll Taxes	FERC_4081	4081005: Payroll Taxes - Fed Unemploy	135,347
3	Payroll Taxes	FERC_4081	4081006: Payroll Taxes - Trimet	2,380,664
4	Payroll Taxes	FERC_4081	4081007: Payroll Taxes - State Umemploy	4,418,310
5	Payroll Taxes	FERC_4081	4081008: Payroll Taxes - Worker's Comp	315,142
6	Payroll Taxes	FERC_4081	4081009: AllocCredit - Payroll Tax	(18,084,329)
7	Property Taxes - Oregon	FERC_4081	4081001: TaxOthThan IncTax-PropTax-Oreg	79,401,382
8	Property Taxes - Washington	FERC_4081	4081002: TaxOthThan IncTax-PropTax-Wash	1,165,414
9	Property Taxes - Montana	FERC_4081	4081003: TaxOthThan IncTax-PropTax-MT	(693,456)
10	Franchise Fees	FERC_4081	4081010: TaxOthThanIncTax-FranFeePort	17,798,959
11	Franchise Fees	FERC_4081	4081011: TaxOthThanIncTax-FranFeeOthCit	37,890,476
12	Foreign Insurance Excise Tax	FERC_4081	4081012: TaxOthThanIncTx-ForInsrExcisTx	82,323
13	Misc. Tax & Lic Fees - Oregon	FERC_4081	4081013: TaxOthThanIncTx-MiscTax&Lic-OR	2,500,549
14	Misc. Tax & Lic Fees - Montana	FERC_4081	4081014: TaxOthThanIncTx-MiscTax&Lic-MT	448,759
15	Oregon CAT	4091O	4091230: OR Corp Activity Tax-Utility	8,741,977
				165,833,151

PGE
UE 435
Exhibit 206
Taxes Other Than Income
Not Scaled

Line No.	Item	FERC	Account	Dec - 2024
1	Payroll Taxes	FERC_4081	4081004: Payroll Taxes - FICA	35,354,336
2	Payroll Taxes	FERC_4081	4081005: Payroll Taxes - Fed Unemploy	148,449
3	Payroll Taxes	FERC_4081	4081006: Payroll Taxes - Trimet	2,627,397
4	Payroll Taxes	FERC_4081	4081007: Payroll Taxes - State Umemploy	4,843,538
5	Payroll Taxes	FERC_4081	4081008: Payroll Taxes - Worker's Comp	190,834
6	Payroll Taxes	FERC_4081	4081009: AllocCredit - Payroll Tax	(20,689,237)
7	Property Taxes - Oregon	FERC_4081	4081001: TaxOthThan IncTax-PropTax-Oreg	87,957,899
8	Property Taxes - Washington	FERC_4081	4081002: TaxOthThan IncTax-PropTax-Wash	1,731,240
9	Property Taxes - Montana	FERC_4081	4081003: TaxOthThan IncTax-PropTax-MT	5,603,320
10	Franchise Fees	FERC_4081	4081010: TaxOthThanIncTax-FranFeePort	19,957,300
11	Franchise Fees	FERC_4081	4081011: TaxOthThanIncTax-FranFeeOthCit	42,693,290
12	Foreign Insurance Excise Tax	FERC_4081	4081012: TaxOthThanIncTx-ForInsrExcisTx	-
13	Misc. Tax & Lic Fees - Oregon	FERC_4081	4081013: TaxOthThanIncTx-MiscTax&Lic-OR	2,542,332
14	Misc. Tax & Lic Fees - Montana	FERC_4081	4081014: TaxOthThanIncTx-MiscTax&Lic-MT	975,696
15	Oregon CAT	4091O	4091230: OR Corp Activity Tax-Utility	12,316,000
				196,252,393

PGE
UE 435
Exhibit 206
Taxes Other Than Income
Not Scaled

Line No.	Item	FERC	Account	Dec - 2025
1	Payroll Taxes	FERC_4081	4081004: Payroll Taxes - FICA	37,510,259
2	Payroll Taxes	FERC_4081	4081005: Payroll Taxes - Fed Unemploy	175,826
3	Payroll Taxes	FERC_4081	4081006: Payroll Taxes - Trimet	2,793,074
4	Payroll Taxes	FERC_4081	4081007: Payroll Taxes - State Umemploy	5,097,611
5	Payroll Taxes	FERC_4081	4081008: Payroll Taxes - Worker's Comp	203,995
6	Payroll Taxes	FERC_4081	4081009: AllocCredit - Payroll Tax	(21,872,105)
7	Property Taxes - Oregon	FERC_4081	4081001: TaxOthThan IncTax-PropTax-Oreg	93,769,462
8	Property Taxes - Washington	FERC_4081	4081002: TaxOthThan IncTax-PropTax-Wash	1,720,776
9	Property Taxes - Montana	FERC_4081	4081003: TaxOthThan IncTax-PropTax-MT	7,305,793
10	Franchise Fees	FERC_4081	4081010: TaxOthThanIncTax-FranFeePort	75,190,752
11	Franchise Fees	FERC_4081	4081011: TaxOthThanIncTax-FranFeeOthCit	-
12	Foreign Insurance Excise Tax	FERC_4081	4081012: TaxOthThanIncTx-ForInsrExcisTx	-
13	Misc. Tax & Lic Fees - Oregon	FERC_4081	4081013: TaxOthThanIncTx-MiscTax&Lic-OR	2,542,332
14	Misc. Tax & Lic Fees - Montana	FERC_4081	4081014: TaxOthThanIncTx-MiscTax&Lic-MT	569,891
15	Oregon CAT	4091O	4091230: OR Corp Activity Tax-Utility	12,968,640
				217,976,305

PGE
UE 435
Exhibit 207
Rate Base
Scaled (Thousands)

Line No.	Line	Based on Ending Balances
1	Plant in Service	13,651,008
2	Less: Accumulated Depreciation/Amortization	(5,781,118)
3	Accumulated Deferred Taxes	(719,665)
4	Accumulated Deferred ITC	
5		
6	**Net Utility Plant**	7,150,225
7		
8	**Operating Materials and Fuel Stocks**	103,783
9		
10	**Deferred Debits**	
11	Glass Insulators	5,555
12	Major Maintenance Accruals	(438)
13	Cloud-Based License and Hosting Fees	
14	Dispatchable Standby Generation	22,762
15	Wheatridge O&M Start-up Costs	1,376
16		
17	**Deferred Credits**	-
18	Injuries & Damages	(6,847)
19	Customer Deposits	(12,632)
20	Incentive Adjustment (UE 283)	(5,000)
21	Post Retirement Liabilities	(14,101)
22	Misc. Other	(669)
23		
24		
25	**Working Capital**	103,410
26		
27	**Rate Base**	7,347,424

PGE
UE 435
Exhibit 208
Rate Base Comparison
Scaled (Thousands)

Line No.	Line	UE 416 Approved Order No. 23-386	UE 427 - Clearwater RAAC	Subtotal UE 416 + UE 427
1	Plant in Service	12,168,909	432,662	12,601,571
2	Less: Accumulated Depreciation/Amortization	(5,438,606)	(16,845)	(5,455,451)
3	Accumulated Deferred Taxes	(699,200)	19,269	(679,931)
4	Accumulated Deferred ITC			
5				
6	**Net Utility Plant**	6,031,103	435,086	6,466,190
7				
8	**Operating Materials and Fuel Stocks**	91,228	-	91,228
9				
10	**Deferred Debits**			
11	Glass Insulators	5,847		5,847
12	Major Maintenance Accruals	(1,775)		(1,775)
13	Cloud-Based License and Hosting Fees	8,227		8,227
14	Dispatchable Standby Generation	4,197		4,197
15	Wheatridge O&M Start-up Costs	1,429		1,429
16				
17	**Deferred Credits**			
18	Injuries & Damages	(8,240)		(8,240)
19	Customer Deposits	(10,973)		(10,973)
20	Incentive Adjustment (UE 283)	(5,500)		(5,500)
21	Post Retirement Liabilities	(29,804)		(29,804)
22	Misc. Other	(714)		(714)
23				
24				
25	**Working Capital**	98,071	(2,473)	95,598
26				
27	**Rate Base**	6,183,096	432,613	6,615,709

PGE
UE 435
Exhibit 208
Rate Base Comparison
Scaled (Thousands)

Line No.	Line	Test Year at GRC Rates	2025 Variance to Approved
1	Plant in Service	13,651,008	1,049,437
2	Less: Accumulated Depreciation/Amortization	(5,781,118)	(325,667)
3	Accumulated Deferred Taxes	(719,665)	(39,734)
4	Accumulated Deferred ITC		
5			
6	**Net Utility Plant**	7,150,225	684,036
7			
8	**Operating Materials and Fuel Stocks**	103,783	12,555
9			
10	**Deferred Debits**		
11	Glass Insulators	5,555	(292)
12	Major Maintenance Accruals	(438)	1,338
13	Cloud-Based License and Hosting Fees		(8,227)
14	Dispatchable Standby Generation	22,762	18,564
15	Wheatridge O&M Start-up Costs	1,376	(53)
16			
17	**Deferred Credits**		
18	Injuries & Damages	(6,847)	1,393
19	Customer Deposits	(12,632)	(1,659)
20	Incentive Adjustment (UE 283)	(5,000)	500
21	Post Retirement Liabilities	(14,101)	15,703
22	Misc. Other	(669)	45
23			
24			
25	**Working Capital**	103,410	7,812
26			
27	**Rate Base**	7,347,424	731,715

PGE
UE 435
Exhibit 209
Production Tax Credits (PTCs) in Net Variable Power Cost
Not Scaled

Line No.	Line	System
1		
2	**Production Tax Credits (PTCs) in 2019 Net Variable Power C**	
3		
4	Grossed Up for Taxes	(80,138,221)
5	Gross-Up Factor	1.368
6	PTCs	(58,595,832)

PGE
UE 435
Exhibit 210
Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Other Production	NVPC	Transmission
1	Operating Revenues			
2	Sales to Consumers (Rev. Req.)	699,528	931,012	138,996
3	Sales for Resale			
4	Other Revenue Detail	16,747		14,061
5	Total Operating Revenues	716,275	931,012	153,057
6				
7	Operation & Maintenance			
8	Net Variable Power Cost		922,992	
9	Total Fixed O&M	152,349		19,242
10	Other O&M	67,165	4,500	10,700
11	Total Operating & Maintenance	219,515	927,493	29,941
12				
13	Depreciation & Amortization	182,734		34,988
14	Other Taxes / Franchise Fees	51,341		13,054
15	Utility Income Tax	49,548	702	14,495
16				
17	Total Oper. Expenses & Taxes	503,138	928,195	92,479
18				
19	Utility Operating Income	213,137	2,817	60,579
20				
21	Rate of Return w-o UE 416 Adjustment	7.19%	7.19%	7.19%
22				
23	Return on Equity	9.75%	9.75%	9.75%
24				
25				
26	**Rate Base**			
27	Gross Plant	5,433,508		1,353,541
28	Accum. Deprec. / Amort	(2,073,690)		(441,158)
29	Accum. Def Tax	(437,375)		(79,951)
30				
31				
32	Net Utility Plant	2,922,442	-	832,432
33				
34	Operating Materials & Fuel	67,318		2,124
35	Misc. Deferred Debits	23,700		5,555
36	Misc. Deferred Credits	(7,859)		(1,358)
37	Working Cash	21,242	39,188	3,904
38				

PGE
UE 435
Exhibit 210
Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Other Production	NVPC	Transmission
39	Total Rate Base	3,026,844	39,188	842,657
40				
41	*Weighted Cost of Debt*	2.31%	2.31%	2.31%
42	*Equity Share of Cap Structure*	50.00%	50.00%	50.00%
43	Excess Cost of Removal (COR) Reversal	1,474		222

PGE
UE 435
Exhibit 210
Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Distribution	Ancillary	Billing
1	Operating Revenues			
2	Sales to Consumers (Rev. Req.)	957,557	7,831	48,131
3	Sales for Resale			
4	Other Revenue Detail	23,295	(7,831)	
5	Total Operating Revenues	980,851	-	48,131
6				
7	Operation & Maintenance			
8	Net Variable Power Cost			
9	Total Fixed O&M	209,199		
10	Other O&M	106,004		36,085
11	Total Operating & Maintenance	315,202	-	36,085
12				
13	Depreciation & Amortization	227,955		5,933
14	Other Taxes / Franchise Fees	145,675		1,697
15	Utility Income Tax	58,242		875
16				
17	Total Oper. Expenses & Taxes	747,074	-	44,589
18				
19	Utility Operating Income	233,777	-	3,541
20				
21	Rate of Return w-o UE 416 Adjustment	7.19%		7.19%
22				
23	Return on Equity	9.75%	(4.63%)	9.75%
24				
25				
26	**Rate Base**			
27	Gross Plant	6,395,888		118,959
28	Accum. Deprec. / Amort	(2,994,429)		(67,720)
29	Accum. Def Tax	(189,820)		(3,022)
30				
31				
32	Net Utility Plant	3,211,639	-	48,217
33				
34	Operating Materials & Fuel	34,341		
35	Misc. Deferred Debits			
36	Misc. Deferred Credits	(25,644)		(839)
37	Working Cash	31,541		1,883
38				

PGE
UE 435
Exhibit 210
Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Distribution	Ancillary	Billing
39	Total Rate Base	3,251,876	-	49,260
40				
41	*Weighted Cost of Debt*	2.31%	2.31%	2.31%
42	*Equity Share of Cap Structure*	50.00%	50.00%	50.00%
43	Excess Cost of Removal (COR) Reversal	566		11

PGE
UE 435
Exhibit 210
Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Metering	Consumer	Total
1	Operating Revenues			
2	Sales to Consumers (Rev. Req.)	2,439	141,336	2,926,830
3	Sales for Resale			
4	Other Revenue Detail			46,271
5	Total Operating Revenues	2,439	141,336	2,973,102
6				
7	Operation & Maintenance			
8	Net Variable Power Cost			922,992
9	Total Fixed O&M			380,790
10	Other O&M	1,115	98,782	324,351
11	Total Operating & Maintenance	1,115	98,782	1,628,133
12				
13	Depreciation & Amortization	362	24,939	476,911
14	Other Taxes / Franchise Fees	194	6,016	217,976
15	Utility Income Tax	141	2,335	126,338
16				
17	Total Oper. Expenses & Taxes	1,812	132,071	2,449,358
18				
19	Utility Operating Income	627	9,265	523,743
20				
21	Rate of Return w-o UE 416 Adjustment	7.19%	7.19%	7.19%
22				
23	Return on Equity	9.75%	9.75%	9.75%
24				
25				
26	**Rate Base**			
27	Gross Plant	56,238	292,874	13,651,008
28	Accum. Deprec. / Amort	(46,210)	(157,910)	(5,781,118)
29	Accum. Def Tax	(1,310)	(8,187)	(719,665)
30				
31				
32	Net Utility Plant	8,718	126,777	7,150,225
33				
34	Operating Materials & Fuel			103,783
35	Misc. Deferred Debits			29,255
36	Misc. Deferred Credits	(75)	(3,474)	(39,249)
37	Working Cash	77	5,576	103,410
38				

PGE
UE 435
Exhibit 210
Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Metering	Consumer	Total
39	Total Rate Base	8,719	128,879	7,347,424
40				
41	*Weighted Cost of Debt*	2.31%	2.31%	2.31%
42	*Equity Share of Cap Structure*	50.00%	50.00%	50.00%
43	Excess Cost of Removal (COR) Reversal	4	33	2,309

II. PGE'S Capital Cost Management Practices

Q. Please provide a high-level overview of PGE's capital cost management practices.

A. PGE employs a simultaneous bottom-up and top-down approach to cost management, with multiple layers of controls. PGE's annual capital budgeting process is governed primarily by three groups: PGE's Board of Directors (BOD), the Capital Review Group (CRG), and Business Sponsor Groups (BSG). This is a layered process which is explained in more detail below, but here is a brief summary. From the "bottom-up," based on rigorous review of projects' need, scope, budget, and forecast, the BSG approves a portfolio of projects for funding. This is shared with the CRG which adjusts funding priorities across PGE. The aggregate annual budget is presented to the BOD for review and approval. The rigorous review is continuous, and the BOD budget review is performed once annually with incremental changes and revisions submitted and reviewed as needed. From the "top-down," the BOD is the ultimate decision-maker for determining the amount of capital available across PGE. The CRG then allocates this to BSGs based on funding allocation priorities, and then each BSG manages its allocation by reprioritizing and balancing its portfolio of projects.

Q. Please briefly describe the role and responsibilities of the BOD, CRG, and BSGs in establishing PGE's annual capital budget.

A. The BOD is responsible for reviewing and approving the annual capital budget. In addition, the BOD approves large strategic projects and future-year obligations for long-lead-time equipment purchases. To the extent additional capital funds are needed after the annual budget is approved, the BOD must approve any additional spending. Finally, the BOD also determines the CEO's extended approval authority, which provides the CEO with limited authority to approve budgets over the BOD-approved amount.

The annual capital budget is recommended to the BOD by the CRG. The CRG develops the proposed annual budget based on the rigorous portfolio development and management of each BSG, and evaluates the use of funds throughout the year on a monthly basis. Each BSG develops a proposed annual budget based on its three- to five-year project road map that prioritizes projects based on PGE's strategic initiatives to benefit customers and project readiness.

Q. Once the annual budget is approved, how are funds managed within the year?

A. Portfolio Managers and Project Managers oversee the daily control of portfolios and projects. Monthly reports and monthly funding requests are provided to the BSG for review and consideration. The CRG reviews the funding requests, the overall impact to PGE's portfolio and strategic goals, and is responsible for approving the annual budgets allocated to each BSG.

To the extent funds in excess of the annual approved amount are requested, the following tools are available: seek reallocation of funds between BSGs; reject funds requested; require budget cuts across other projects; access reserves funding[7] within the BSG; access funds called "non-budgeted CEO matters" which is an amount of reserve funding that can be used in emergency situations or as temporary allocations; or go to the BOD for additional funds.

Q. How does PGE manage capital costs over multiple years to balance customer price impacts against the necessity of maintaining a reliable and safe system?

A. PGE incorporates a multi-year outlook in our capital planning and management in several ways. The BSG develops three- and five-year roadmaps which estimate projects over a longer-term duration. This provides the BSG with a broader view of the portfolio and enables the portfolio manager to balance project priority and cost management. The roadmaps enable portfolio managers to maintain funding stability over time and allow PGE executives to monitor the overall trend of the capital programs. PGE also employs analytical tools like asset risk models, system planning models, customer forecasts, and community development plans to help drive long term plans. With this multi-year perspective, PGE leaders can carefully balance customer price impacts with the need to invest in a reliable and safe system.

Q. Given the pivotal role of the BSG in PGE's cost control practices, please provide more information about its structure.

A. There are six BSGs under the CRG: Transmission and Distribution (T&D), Generation, Information Technology, Customer Services, Grid Architecture, and Buildings & Vehicles Services. Ninety-four percent of the capital budget is driven by the T&D and Generation BSGs. Each BSG is responsible for approving the right projects to support PGE's ability to

[7] "Reserves" is a funding source that PGE uses to fund stage-gated, emerging, and unanticipated projects that are not fully scoped or known when capital budgets are approved. This includes funding set aside for stage-gated projects, new large customer load requests, unanticipated increases on in-flight projects, or other emerging opportunities during the course of the year. Conversely, when an in-flight project gains efficiency and has dollars to give back, the funding give back will go into the reserves to be allocated elsewhere.

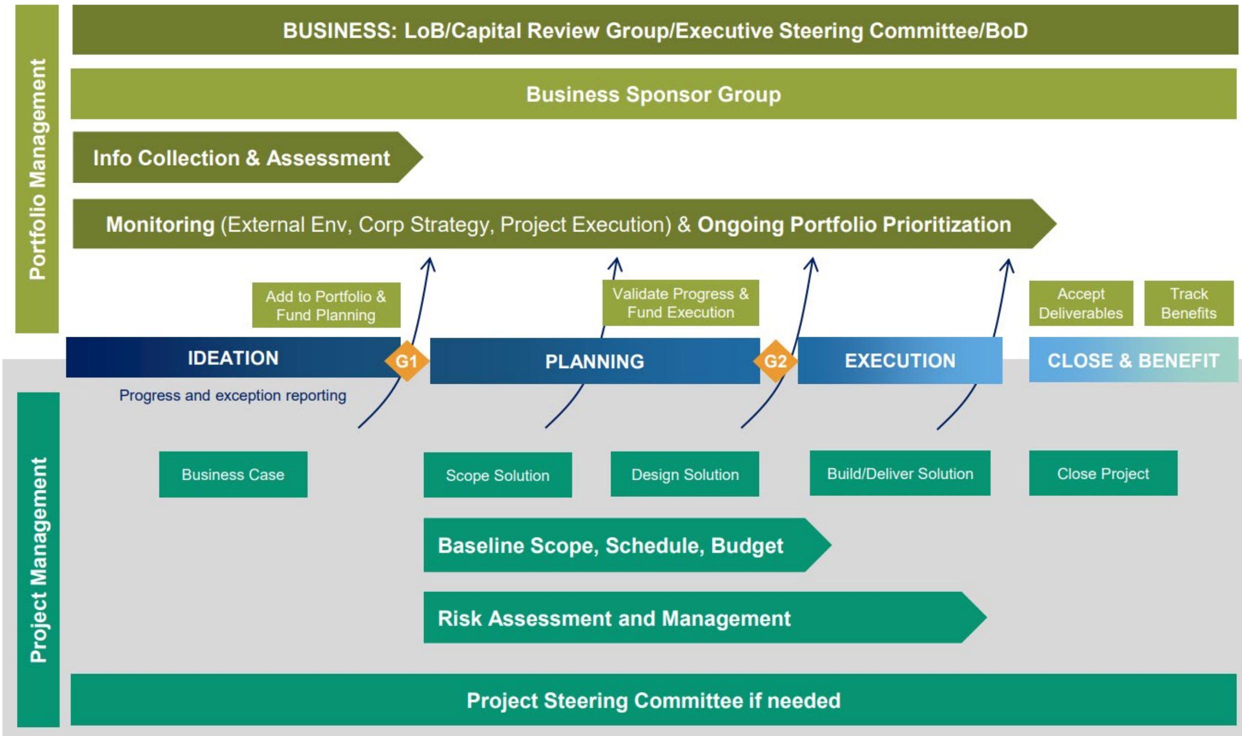
deliver on its strategy for the benefit of its customers. The BSG performs portfolio planning by developing three- to five-year road maps that translate the corporate strategy into specific initiatives and prioritizes project execution and funding. The BSG performs portfolio management by approving projects at stage-gate milestones, allocating funds to projects based on performance, monitoring portfolio execution, and escalating issues to the CRG as needed.

The BSG is comprised of senior leaders within the organization who serve as voting members and cross-functional leaders who serve as non-voting members. The BSG meets monthly to review projects and consider funding requests.

Q. Please provide a visual representation of the project management and cost control measures at the portfolio level.

A. See Figure 1.

Figure 1
Cost Control and Project Management at Portfolio Level



Q. Figure 1 shows two primary workstreams: Portfolio Management and Project Management. Please summarize each of these.

A. Portfolio Management refers to the management of the entire portfolio within a particular area, such as T&D. The two primary leadership roles in Portfolio Management are performed by the BSG leadership and a Portfolio Manager. Portfolio Management decides when projects are ready to move from the roadmap to active work, allocates funds to projects based on performance, approves projects at stage-gate milestones, monitors portfolio execution and delivery of benefits, manages portfolio exceptions, and escalates issues to the CRG as needed. The Portfolio Manager ensures projects benefit customers by aligning with and delivering on PGE's strategy, allocates budgeted dollars to projects based on performance, approve stage-gate milestones for projects, monitors portfolio execution and benefits delivery, manages project expectation, ensures value in the portfolio, actively balances the portfolio, and identifies and escalates issues, as needed.

Project Management refers to the management of an individual project through the stage-gating process by a Project Managers. The Project Manager manages a project's progression through the planning and execution stage-gates and helps keep the project on schedule and within the budget, as discussed in more depth below.

Q. What is the stage-gating process?

A. The stage-gating process is a project management technique that PGE uses to assess project readiness using multiple project stages. Stage-gating helps Project Managers think through common project scoping and execution considerations, and minimize disruptions or scope changes by leveraging thoughtful planning.

There are four stages used by PGE: ideation, planning, execution, and close and benefit. These are shown in the blue rectangles in Figure 1. The work performed by Portfolio Management and Project Management flows through these four stage-gates.

A Project Manager manages each project through the stage-gating process. The first stage is "ideation," where the business case is developed. Upon approval by the Portfolio Manager and BSG leadership, the project moves into the "planning" stage and requests planning dollars. This is shown as the orange diamond labeled "G1" in Figure 1. Planning dollars are generally in the several-hundred-thousand-dollar range and are used to:

- Re-validate the business case, conducting studies and analyses as needed;
- Conduct engineering design;
- Secure permits and property easements;
- Confirm tasks, resources, budget, and schedule; and

- Finalize vendor bids and agreements.

Funding for long-lead-time equipment is also requested during the planning phase. This allows PGE to maintain project timelines because it can take over a year for certain equipment to be delivered. To be clear, procurement of long-lead-time items is not an irrevocable commitment to a project because such items can be repurposed, used as a spare, or sold.

Upon completion of the planning stage, the project is again reviewed by the Portfolio Manager and BSG. If approved, the project then moves into the "execution" stage and requests execution dollars. This is shown as the orange diamond labeled "G2" in Figure 1. By the time execution funds are requested at the conclusion of the planning stage, the Project Manager has performed the due diligence necessary to develop a total project cost estimate, which is presented when requesting execution funds.

While in the execution phase, on a monthly basis, the Project Manager reviews actual spend compared to budget; updates forecast of spend timing; reports and takes action on significant variances; and updates in-service dates. All of this is then reviewed by the Portfolio Manager and shared with the BSG. This is a critical cost control practice employed by PGE.

The fourth and final stage is close and benefit, which occurs when the project goes in-service and all accounting and documentation for the project is completed.

Q. Above you stated that each project undergoes a monthly evaluation where, among other things, actual spend is compared to budget. What happens if there is a variance?

A. Each month, projects in the execution phase with a variance of more than 10 percent between actuals and budget or between forecast and budget are flagged for further scrutiny and analysis by the Portfolio Manager. Results are presented to the BSG. Projects with a variance of more than 10 percent while in the execution phase may be required to limit or reduce funding, or the Project Manager may need to make a case for additional funding. This is another example of the multiple layers of cost control and management employed at PGE. In some cases, funding for projects will be paused if there are concerns with cost management, scope, or timeline.

Q. How does PGE estimate costs in order to request planning and execution funds?

A. The Generation, Transmission and Distribution Project Management Office (GTD PMO) is responsible for estimating costs for capital projects. The estimates are used as the baseline budget requests for the planning and execution gates, with updates to the forecast and budget occurring as actual contract commitments are made. Cost estimates are developed with an in-depth understanding of construction processes and methods. They are data driven with market, actual, and historical information maintained within one estimating database.

PGE employs standardized estimation parameters, shown in Table 1. Planning funds are requested based on a "feasibility estimate," which has a range of accuracy of -30% to +50%, based on Association for the Advancement of Cost Engineering (AACE International) guidelines (see, Stage 3 in Table 1).

Estimate accuracy increases as design progresses. Execution funds are requested based on the "Issued for Construction (IFC) Design Estimate," which has a range of accuracy of -15% to +20% (see Stage 5 in Table 1).

Table 1
Standardized Estimation Parameters

Project Management Playbook Stages	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5	Stage 6	Stage 7
Playbook Stage Name	Project Planning	Portfolio Planning	Execution Planning	Engineering/ Permitting	Construction Planning	Construction	Project Closeout
Estimate Type and Accuracy	**Conceptual Screening** *-50% to +100%*		**Feasibility Estimate** *-30% to +50%*[1]	**30% Design Estimate** *-20% to +30%*	**IFC Design Estimate** *-15% to +20%*		
Intended Use	Portfolio screening of projects and evaluating options		Request Planning Funds	Update planning fund request (if needed)	Request Execution funds		

Q. You have described the rigor with which PGE plans projects, estimates costs, and employs a stage-gating process to require BSG review and approval prior to receiving funds. Does PGE use other cost control management practices?

A. Yes. PGE has an annual process that must be followed before any money can be spent, called authorization to spend (ATS). This begins with PGE's annual budgeting process in May, when each project submits its annual spending plan for the following year for consideration by the BSG and, ultimately, the CRG. This is called "Capital Call." Between May and November, the Portfolio Manager analyzes the proposed spending requests and modifies the portfolio's three- to five-year roadmap. Based on this analysis, the Portfolio Manager recommends to the BSG approval of funding for projects. Once each BSG has approved its annual spending plan, these are brought to the CRG for review and approval.

Once the CRG approves the spending plan, there is one more step before funds are available to be spent. This is the ATS process, which occurs in November. ATS is the confirmation of budgets submitted in May. Depending on the size of the project's budget, there are multiple layers of approval that are required before funds are authorized to be spent. This is yet another component to PGE's cost control management. In order to have funds released and allowed to be spent based on approved project funds, all projects require the approval of Corporate Planning, Asset Accounting, Environmental Services, the sponsoring department's manager, and the Project Process Administrator.

Additional approvals are required as a project increases in cost. If a project is more than $350,000, it needs the additional approval of the sponsoring department's senior manager. If the project is more than $500,000, it needs the approval of the sponsoring department's director. If the project is more than $1 million, it needs the approval of the organization's vice president and lastly, if the project is more than $5 million, it needs the approval of the Chief Financial Officer. These approvals are sequential and cumulative. For example, if a project is more than $5 million, it will need approval from each layer of management prior to seeking approval from the next higher level of management. If any person in the authority chain rejects a project, the project does not progress up the chain and is sent back to the Project Manager for revision.

Q. Part of cost control management is prioritizing how limited funds are spent. Given Staff's scrutiny of PGE's T&D capital spending, please explain how PGE prioritizes which T&D projects to fund.

A. Projects are identified as belonging to one of four categories: maintaining the business, compliance, customer-driven, and new opportunities. "Maintaining the business" includes necessary work such as rebuilding or replacing defunct equipment for reliability and safety reasons. "Compliance" projects include necessary work to be compliant with the rules and regulations that govern the electric utility, including Facilities Inspection and Treatment to the

National Electrical Safety Code (FITNES) and North American Electric Reliability Corporation (NERC), among other regulatory bodies. "Customer-driven" projects include distribution line construction, substation upgrades, etc. "New opportunities" include pursuits such as energy storage projects.

Projects are prioritized based on business and customer benefit with specific focus on maintaining the business and compliance. Over ninety percent of PGE's annual capital budget is related to must-do projects to maintain the business, comply with regulations, and serve the needs of customers. As an example, only four percent of PGE's 2021 annual T&D portfolio was designated for new opportunities.

Q. Please summarize PGE's cost control management practices.

A. The annual capital budgeting process is governed primarily by three groups: PGE's BOD, the CRG, and the BSGs. PGE employs a simultaneous bottom-up and top-down approach to cost control management, with multiple layers of controls in between. On one end, individual Project Managers create annual capital project plans that are provided to their BSG. There is a Portfolio Manager within each BSG who aggregates the project recommendations and triages them against the BSG's three- to five-year roadmap, forecasted customer demand, and strategic asset management to determine the best portfolio of projects to present to the BSG and CRG. The CRG then reviews the portfolios from each BSG.

On the other end of this process, PGE's BOD reviews and approves the total capital budget based on the aggregated annual plans from the BSGs that were reviewed by the CRG. This approved annual budget is then passed back to the CRG, and the CRG allocates the final dollars to the BSGs, based on the board approved plan for the year.

As a project progresses, variances are assessed each month, and any actual or forecasted variance of more than 10 percent is carefully scrutinized to ensure that the project remains prudent and that project costs are controlled to the maximum extent possible.

PGE Exhibit 212
Unbundled Results of Constable Summary
2025 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total	Check
Operating Revenues									
Sales to Consumers (Rev. Req.)	16,453	353	518	-	-	-	-	17,325	-
Sales for Resale	-	-	-	-	-	-	-	-	-
Other Operating Revenues	-	-	-	-	-	-	-	-	-
Total Operating Revenues	16,453	353	518	-	-	-	-	17,325	
Operation & Maintenance									
Net Variable Power Cost	(9,558)	-	-	-	-	-	-	(9,558)	-
Total Fixed O&M	633	350	-	-	-	-	-	983	-
Other O&M	153	2	72	-	-	-	-	227	-
Total Operation & Maintenance	(8,771)	352	72	-	-	-	-	(8,348)	
Depreciation & Amortization	8,269	-	-	-	-	-	-	8,269	-
Other Taxes / Franchise Fee	2,353	-	444	-	-	-	-	2,797	-
Income Taxes	4,078	0	0	-	-	-	-	4,078	-
Total Oper. Expenses & Taxes	5,929	352	517	-	-	-	-	6,797	
Utility Operating Income	10,525	1	2	-	-	-	-	10,528	
Rate of Return	7.19%	7.19%	7.19%					7.19%	
Return on Equity	9.75%	9.75%	9.75%					9.75%	
Rate Base									
Utility Plant in Service	157,058	-	-	-	-	-	-	157,058	-
Accumulated Depreciation	(8,269)	-	-	-	-	-	-	(8,269)	-
Accumulated Def. Income Taxes	(2,636)	-	-	-	-	-	-	(2,636)	-
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-	-	-	-
Net Utility Plant	146,152	-	-	-	-	-	-	146,152	
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-
Misc Deferred Debits	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-
Working Cash	250	15	22	-	-	-	-	287	-
Total Rate Base	146,403	15	22	-	-	-	-	146,439	

PGE Exhibit 213
Unbundled Results of Seaside Summary
2025 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total	Check
Operating Revenues									
Sales to Consumers (Rev. Req.)	47,469	504	1,479	-	-	-	-	49,453	-
Sales for Resale	-	-	-	-	-	-	-	-	-
Other Operating Revenues	-	-	-	-	-	-	-	-	-
Total Operating Revenues	47,469	504	1,479	-	-	-	-	49,453	
Operation & Maintenance									
Net Variable Power Cost	(20,657)	-	-	-	-	-	-	(20,657)	-
Total Fixed O&M	2,464	500	-	-	-	-	-	2,964	-
Other O&M	411	2	205	-	-	-	-	619	-
Total Operation & Maintenance	(17,782)	502	205	-	-	-	-	(17,074)	
Depreciation & Amortization	20,850	-	-	-	-	-	-	20,850	-
Other Taxes / Franchise Fee	6,563	-	1,269	-	-	-	-	7,832	-
Income Taxes	11,267	0	1	-	-	-	-	11,269	-
Total Oper. Expenses & Taxes	20,899	503	1,475	-	-	-	-	22,876	
Utility Operating Income	26,571	2	4	-	-	-	-	26,577	
Rate of Return	7.19%	7.19%	7.19%					7.19%	
Return on Equity	9.75%	9.75%	9.75%					9.75%	
Rate Base									
Utility Plant in Service	396,000	-	-	-	-	-	-	396,000	-
Accumulated Depreciation	(20,850)	-	-	-	-	-	-	(20,850)	-
Accumulated Def. Income Taxes	(6,430)	-	-	-	-	-	-	(6,430)	-
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-	-	-	-
Net Utility Plant	368,720	-	-	-	-	-	-	368,720	
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-
Misc Deferred Debits	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-
Working Cash	882	21	62	-	-	-	-	966	-
Total Rate Base	369,602	21	62	-	-	-	-	369,686	

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Corporate Support and Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Joe Trpik
Anne Mersereau
Greg Batzler

February 29, 2024

Table of Contents

I. Introduction

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

A. My name is Joe Trpik. My Position is Senior Vice President, Chief Financial Officer. My qualifications appear at the end of this testimony.

My name is Anne Mersereau. My position is Vice President, Human Resources, Diversity, Equity & Inclusion at PGE. My qualifications appear at the end of this testimony.

My name is Greg Batzler. I am 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. We explain PGE's request for approximately $221.7 million in administrative and general (A&G) costs in 2025, a decrease of $13.8 million compared to the 2024 budget of $235.5 million.[1] Additionally, we present PGE's 2025 Total Compensation forecast of $597.3 million, including total labor costs, incentives, and benefits, an increase of $7.5 million, or 1.3%, compared to 2024 budgeted amounts of $589.7 million.

Q. Why are you comparing PGE's 2025 test year forecast to the 2024 budget, rather than 2023 actuals?

A. We do this because the 2024 budget approximates the final Docket No. UE 416 (UE 416) costs that are currently in PGE's retail rates, as approved by Commission Order No. 23-386. As 2025 is only one year beyond the UE 416 test year of 2024, it is the most accurate comparable basis from which to discuss changes expected in 2025 is PGE's 2024 budget. However, for comparison purposes, the tables below also present 2023 actuals in addition to 2024 budget and 2025 forecast amounts.

[1] Unless specifically indicated as capital costs, all A&G costs in this testimony refer to O&M costs.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II – Overview and Summary
- Section III – Corporate Support
- Section IV – Total Compensation
- Section V – Qualifications

II. Overview and Summary

Q. Please summarize your request for this filing.

A. We request that the Commission approve PGE's forecast of $221.7 million of A&G costs in the 2025 test year, which represents a $13.8 million decrease from 2024 budget. We request that the Commission approve PGE's IT related capital additions of $68.8 million as well as our IT O&M forecast of $83.0 million. Finally, we request that the Commission approve PGE's forecast of $597.3 million of total compensation costs in the 2025 test year.

Q. How would approval of PGE's request benefit customers?

A. The values above include amounts for continued insurance coverage, which benefits customers as it helps to protect customers against increased risks, premium volatility, and higher costs associated with being underinsured. IT investments better equip our workforce to serve our customers efficiently and effectively. Through IT upgrades, customers benefit from programs that protect against cyberattacks as well as software that helps prevent damages to the underground wires serving customers. Competent and skilled employees are needed to successfully execute customer programs, keep costs low, and support the delivery of safe, reliable power. Competitive compensation attracts and helps retain those strong employees.

III. Corporate Support

Q. What functions are classified as A&G and what are the costs of these functions?

A. We classify A&G as the back-office functions that support PGE's direct operations that deliver safe, reliable, clean, and affordable energy to customers. This includes human resources (HR), accounting and finance, insurance, supply chain, corporate security and business continuity, regulatory affairs, legal services, and information technology (IT). We also include other costs such as employee benefits and incentives, support services, and regulatory fees that fall within the Federal Energy Regulatory Commission's (FERC) definition of A&G.[2] PGE Exhibit 301 provides a list of A&G functions plus a summary of costs for 2021 (actuals) through 2025 (test year forecast). Table 1 below summarizes major A&G costs for 2024 budget and the 2025 test year by functional area.

[2] FERC defines Administrative and General expenses as those that fall within FERC accounts 920 through 935.

Table 1
A&G Costs by Major Functional Area ($ millions)

Major Functional Areas	**2023 Actuals**	**2024 Budget**	**2025 Forecast**	**2024-2025 Delta***
Accounting/Finance	$ 14.4	$ 13.8	$ 14.8	$ 1.0
Business Support Services	1.7	1.3	1.6	0.3
Corp Communications/Public Affairs	3.2	4.6	5.0	0.4
Corporate Governance	8.4	6.6	6.8	0.2
Corporate R&D	2.6	2.7	3.5	0.8
Environmental Services	1.6	2.5	2.5	0.0
Facilities/Rent	4.1	4.9	5.0	0.1
Governmental Affairs	1.7	2.0	2.2	0.2
HR/Employee Support (net of capital allocs.)	11.3	12.3	13.1	0.8
Hydro Licensing and Support	0.0	0.02	0.02	0.0
Insurance	18.8	19.9	21.9	2.0
IT: Direct & Allocated[3]	16.3	15.4	18.2	2.8
Legal	6.7	9.1	9.7	0.6
Performance Management	0.1	0.3	0.3	0.0
Regulation	3.4	4.2	3.8	(0.4)
Physical Security and Business Continuity	4.1	5.2	5.3	0.1
Supply Chain/Contract Services/Purchasing	3.7	3.3	3.5	0.2
Sustainability and Resource Planning	1.1	2.3	1.8	(0.5)
Total for Major Functional Areas*	**$ 103.3**	**$ 110.4**	**$ 119.1**	**$ 8.7**
Benefits (net of capital allocs.)	42.8	53.1	57.9	4.8
Corporate Allocations (net)	(4.7)	(7.8)	(8.8)	(1.0)
Corporate Cost Reductions	0.0	(3.7)	(3.4)	0.3
General Plant Maintenance	4.6	4.6	4.2	(0.4)
Incentives	44.8	48.5	17.9	(30.6)
LC Fees, Revolver Fees, Margin Net Int., & Broker Fees	4.2	3.6	3.5	(0.1)
Membership Expense	2.8	3.3	3.5	0.2
Regulatory Fees	12.8	14.9	16.6	1.7
Severance	1.3	0.0	0.0	0.0
Total Labor Loadings to A&G	0.0	0.0	2.4	2.4
Total PTO to A&G	7.9	8.4	8.8	0.3
Total Other A&G Costs*	**$ 116.4**	**$125.0**	**$102.6**	**$ (24.4)**
Total A&G*	**$ 219.7**	**$ 235.5**	**$ 221.7**	**$ (13.8)**

*****_May not sum due to rounding_

Q. How would you characterize the forecasted change in A&G costs from 2024 to 2025?

A. Total A&G costs decrease overall when comparing 2024 budget to the 2025 forecast. Within the 2025 forecast, cost increases are within three primary areas: insurance, benefits, and IT. Insurance costs continue to be subject to the same trends that we identified in PGE's 2024 general rate case (UE 416) and are described in detail in Section III (A). Benefits, as

[3] "IT: Direct & Allocated" as referenced in Table 1 only applies to amounts for A&G, for information on the entirety of IT see Section III of this testimony.

discussed in Section IV of this testimony, are largely driven by medical, dental, and retirement costs. While we actively manage costs associated with insurance and benefits, they are primarily external to PGE and increase in costs reflect larger market conditions and/or regulatory requirements beyond our control. We also forecast a modest increase in IT as these systems continue to be integral to all aspects of PGE's operations. IT costs are described in Section III (B).

Q. Has PGE included any adjustments for meals and entertainment in its 2025 O&M forecast?

A. Yes. We reduced our meals and entertainment (M&E) 2025 forecast by $275 thousand, which is approximately 50% of the M&E costs incurred within A&G during 2023.

A. Insurance

Q. What types of insurance coverage does PGE maintain?

A. In general, the insurance coverage maintained by PGE falls into two broad programs: Property and Casualty. PGE maintains a prudent portfolio of insurance coverage consistent with industry peers, which we list and describe in PGE Exhibit 302 and Confidential PGE Exhibit 303. 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. We discuss PGE's insurance coverage, as well as retained losses, below.

Q. What is PGE's forecast for insurance premiums for 2025?

A. As shown in Table 2 below, we expect total Property and Casualty premiums to be approximately $32.6 million. This compares to 2024 budgeted premiums of $27.7 million, an increase of 17.4%.

Table 2
Insurance Premiums ($ millions)

Type of Loss	2023 Actuals**	2024 Budget**	2025 Forecast**	2024-2025 % Increase
Property	$11.2	$6.2	$6.8	9.4%
Casualty	$11.1	$21.6	$25.8***	19.7%
Totals*	**$22.2**	**$27.7**	**$32.6**	**17.4%**

**May not sum due to rounding.*
***Premium amounts do not include membership credits*
****Premium amounts exclude 50% of D&O premium*

Q. What is reflected in PGE's 2025 revenue requirement for insurance premiums?

A. Amounts included within PGE's revenue requirement and provided as part of Table 1 are consistent with how PGE records insurance costs under Generally Accepted Accounting Principles, using the accrual basis of accounting. That is, insurance costs are recorded consistent with the period of coverage. By contrast, the costs in Table 2 and amounts discussed within this section are presented by insurance policy years (i.e., the year in which the policy premium is payable).

1. Property

Q. What types of coverage are included in PGE's Property insurance program?

A. The lines of coverage in PGE's Property insurance program are as follows:

- All-Risk Property (all PGE assets excluding transmission and distribution)
- Fidelity & Crime; and
- Sabotage & Terrorism.

Q. What changes do you expect in Property insurance premiums?

A. Calendar year 2023 was the sixth year since 2017 that the global Property insurance market saw losses from natural catastrophes in excess of $100 billion.[4] As a result of these challenges,

[4] *See* Freedman, Andrew, "Global insured disaster losses in 2023 to top $100B," AXIOS (October 19, 2023), available at https://www.axios.com/2023/10/19/extreme-weather-insurance-costs.

insurance underwriters continue to seek double-digit rate increases while pushing for higher deductibles and/or reducing available limits.

As a result of these market conditions, PGE restructured its Property insurance program beginning in 2024. Overall, from 2023 to the 2025 forecast, PGE is experiencing a 39.8% reduction in Property insurance premiums. This is the result of a significant decrease from restructuring the program in 2024, offset by a smaller increase of 9.7% from 2024 to 2025.

Q. Please provide more detail on the restructuring of PGE's Property insurance program.

A. Like most investor-owned utilities' Property insurance, PGE's prior Property insurance program was comprised of more than ten insurers (United States and London) that subscribed on a quota share basis. The new program, effective January 1, 2024, is led by Everen Limited out of Bermuda and provides a single large block of capacity for all of PGE's assets (excluding transmission and distribution). Because Everen is a post-loss funding mutual insurance company, it offers insurance to its members "at cost" (premiums are derived from claims costs and expenses only), and loss funding (premiums) are spread over a rolling 5-year period to reduce premium volatility and make premiums more predictable over time. Everen's membership is comprised of 68 current members who make up some of the largest energy companies around the world. While Everen was established in 1972, it was not until the early 2000s that membership was opened to electric utilities (of the 64 Everen members, six are U.S. electric utilities).

2. Casualty

Q. What types of coverage are included in PGE's Casualty insurance program?

A. The lines of coverage in PGE's Casualty insurance program are as follows:

- General & Auto Liability

- Directors and officers (D&O) Liability
- Fiduciary Liability
- Workers' Compensation
- Nuclear Liability
- Cyber Liability
- Aviation Hull & Liability (Including Unmanned Aircraft Systems)
- Sabotage & Terrorism
- Surety Bonds

PGE Exhibit 302 describes each policy's purpose in more detail.

Q. What changes do you expect in Casualty insurance premiums?

A. PGE expects a premium increase of 22.0% in its General & Auto Liability insurance program. The adverse impacts of wildfire losses over the last decade continue to be a primary driver of this premium increase. Additionally, the 2020 Labor Day fires in the Pacific Northwest specifically, along with subsequent fires across the country from 2020 through 2023[5] in general, have continued to shed light on the catastrophic exposure faced by utilities in the region. Other exposures that increase underwriting scrutiny and adversely impact utility insurance pricing in the U.S. and Bermuda markets continue to be the perceived risk of large auto fleets, gas pipeline infrastructure, use of drones, hydro facilities, and their safety protocols, and high-dollar verdicts involving liability claims greater than $10.0 million.

Workers' Compensation insurance is expected to see continued rate increases above 10% primarily due to industry-wide losses combined with a general rise in medical costs, inflation,

[5] Beachie Creek, Archie Creek, Holiday Farm, and Slater fires in 2020, Bootleg fire in 2021, Cedar Creek fire in 2022, Smith River Complex and Camp Creek fires in 2023.

wage growth, an aging workforce, along with the ongoing transition back to more of an in-person work environment – all of which put pressure on Workers' Compensation rate adequacy in 2025. Cyber Liability underwriters continue pushing double-digit rate increases, especially in the energy and utility sector due to the high cyber-attack target value of these industries, impacting multiple companies at once. Casualty losses would produce upward pressure on rates beyond the current forecast. Overall, we anticipate a 19.7% increase on premiums over 2024 budget levels without taking into account any unknown increases in premiums we may face due to the ongoing consequences of recent natural disasters discussed above.

Q. Has PGE included 100% of D&O insurance coverage in the 2025 test year?

A. No. We have excluded 50% of D&O insurance coverage costs to reduce the size of our request for the benefit of our customers and consistent with prior settlement terms, though we have previously recovered 100% of these expenses.

3. Retained Losses

Q. What are retained losses?

A. Retained losses are the portion of any claim falling within PGE's self-insured retentions for its Auto Liability, General Liability, and Workers' Compensation claims that are frequent and predictable. Simply put, retained losses are the amounts borne by PGE before any insurance recovery.

Q. What is PGE's forecast of expenditures for retained losses from 2024 to 2025?

A. As shown in Table 3, PGE expects annual retained losses for Workers' Compensation and Auto and General Liability claims to remain flat from 2024 to 2025. In 2024 and 2025, PGE's annual expenditures are budgeted and forecasted at the expected level, based on the actuarial projections, and anticipated claims. PGE budgets for Auto and General Liability retained losses based on actuarial projections. Workers' Compensation retained losses are budgeted by reviewing PGE's prior year's claim experience and adjusting as needed for new and anticipated claims costs.

Table 3
Retained Losses ($ millions)

Type of Loss	2023 Actuals	2024 Budget	2025 Forecast	2024-2025 % Increase
Auto & General Liability	$1.7	$2.5	$2.5	0.0%
Workers' Compensation	$1.4	$1.9	$1.9	0.0%
Totals*	**$3.0**	**$4.4**	**$4.4**	**2.3%**

**May not sum due to rounding*

B. Information Technology

1. IT Capital Projects

Q. Please summarize the major IT capital additions since PGE's last general rate case.[6]

A. PGE is implementing new IT systems and programs to replace aging IT infrastructure as our business continues to grow and increasingly utilizes digital solutions to support the delivery of safe, reliable, clean, and affordable energy. In support of this effort, PGE's major IT projects that will close to plant by December 31, 2024, total approximately $58.4 million. Table 4 below highlights the six major IT project investments included in this case.

Table 4
Major IT Capital Additions ($millions)

Project	Additions
IT Software Blanket	$18.3
Tech Refresh	$15.0
Zero Trust	$5.7
Network Fitness	$5.5
CTO Desktop Fitness	$5.4
Server Storage Fitness	$4.3
Energy Management Systems (EMS) Upgrade	$4.3
Sub-Total of Major IT Capital Additions	**$58.5**
Other IT Capital Additions	$10.3
Total IT Capital Additions	**$68.8**

Q. Please elaborate on what is included in the $58.5 million of major IT investments listed above.

A. Major IT investments include:

- $18.3 million related to a blanket fund for IT Software, to be used for the purchase and replacement of various software programs used to support PGE's utility business.

[6] *In the Matter of Portland General Electric Company, Request for General Rate Revision*, Docket UE 416 set rate base amounts as of December 31, 2023.

- $15.0 million related to the Tech Refresh project, which will modernize and recharge our workforce by replacing Asset and Resource Management (ARM) with options that leverage updated technology and functionality tools to better support PGE's field and scheduling work, provide mobile friendly opportunities, and better equip our workforce to serve our customers efficiently and effectively.
- $5.7 million related to our Zero Trust program, an enterprise-wide IT initiative that will provide higher levels of network segmentation to provide better visibility, authentication, and control of network access for the purpose of keeping PGE's systems safe from cyberattacks.
- $5.5 million related to network fitness, to fund the review, replacement, and decommissioning of network infrastructure that has reached the end of its useful life including routers, switches, wireless accessories, firewalls, and supporting infrastructure.
- $5.4 million related to desktop fitness, to fund replacement of desktop computers, laptop computers, and other end-user devices that have reached the end of their useful life or otherwise need to be replaced.
- $4.3 million related to server storage fitness, used to replace on-premise computer server infrastructure that has reached the end of its useful life.
- $4.3 million related to an EMS Upgrade, which will keep our Energy Management System current and capable of supporting engineering studies critical to PGE's compliance with FERC Order No. 881.

2. IT O&M

Q. Please summarize the activities PGE categorizes as IT.

A. IT consists of the departments responsible for developing, operating, and maintaining our computer, cyber, information, and communication systems. These systems continue to be increasingly important to all aspects of PGE's operations, with increasing scope, reliance, and use. As PGE modernizes systems and processes, like all providers of critical infrastructure, we are also continuing to be increasingly reliant on evolving technology. This increases our need for more resilient, secure, and reliable systems with which to conduct operations and provide customer service.

As PGE continues to improve the functionality of our systems and customer-focused products and services (in response to customer needs and expectations), our systems are experiencing incremental and continuous evolution. These systems are now more connected and integrated, requiring incremental resources to provide matching cyber capabilities with safer security platforms.

Q. By how much do you forecast IT O&M costs to increase?

A. We forecast IT O&M costs to increase by approximately $9.4 million, from $73.7 million in 2024 to $83.0 million in 2025, as shown in Table 5 below. Because these costs relate to all areas of PGE's operations, they are directly charged or allocated to appropriate operating areas and appear as part of each area's O&M costs. Consequently, we discuss IT as a whole in this section of the testimony rather than just the portion charged to A&G.

Table 5
Total IT O&M Costs ($ millions)

Category	2023 Actuals	2024 Budget	2025 Forecast	2024-2025 Delta
Direct Charges to Operating Areas	$29.6	$23.0	$27.3	$4.4
Allocated Charges to Operating Areas	$44.6	$50.7	$55.7	$5.0
Total IT*	**$74.2**	**$73.7**	**$83.0**	**$9.4**

Q. Please elaborate on direct charging and allocating IT expenses.

A. As shown in Table 5 above, PGE's IT costs fall into two categories: directly charged and allocated. Directly charged costs relate to systems that are specific to a given operating area, such as transmission, distribution, or customer service. Consequently, these costs are charged directly to specific O&M accounts related to those operating areas. Other IT work in the areas of voice, data, network, communications, business recovery, the data center, and office systems, does not benefit any specific operating area alone; instead, these costs apply broadly to all PGE activities and departments. These costs are first charged to a balance sheet account (Account No. 1840004 – IT Service Provider) and then allocated to expense accounts for the various operating areas. PGE Exhibit 305 provides a summary of the direct and allocated charges by operating area.

Q. What are the major drivers of the forecasted IT O&M cost increase from 2024 to 2025?

A. Major drivers of the variance between 2024 budget and the 2025 forecast of IT O&M include:

- IT software and hardware support – we forecast an additional $4.7 million from the 2024 budget to fund positions supporting IT software and hardware. Specifically, the increased labor will provide Day 2 support (i.e., on-going systems maintenance) of capital projects included within PGE's Tech Roadmap.
- Application support - including support for Enterprise Resource Planning (ERP), IQGeo, Maximo, and mobile support – we forecast an approximate $1.4 million

increase in 2025 to support investment in various applications.

- Escalations – we forecast an additional $1.2 million increase due to escalations in 2025. For more information about escalation rates see Exhibit 200.

IV. Total Compensation

Q. Please summarize your total compensation costs in 2025.

A. As shown below in Table 6, we forecast total compensation costs to increase from the 2024 budget to 2025 forecast by $7.5 million, driven by increases in benefits expenses and labor escalation rates.

Table 6
Total Compensation Costs By Type ($ Millions)

Component	2023 Actuals	2024 Budget	2025 Test Year	2024-2025 Delta
Total Labor	$432.6	$441.2	$470.4	$29.1
Incentives	$44.8	$48.5	$17.9	$(30.6)
Benefits	$88.0	$99.9	$108.9	$9.0
Total Compensation*	**$565.4**	**$589.7**	**$597.3**	**$7.5**

** Numbers may not sum due to rounding*

A. Total Compensation Philosophy

Q. Please briefly describe PGE's total compensation goals.

A. PGE's goal is to provide a total compensation package sufficient to attract, develop, and retain a diverse group of employees with strong qualifications and skills.

Q. How does PGE control costs while striving to achieve this goal?

A. To keep prices affordable for customers, PGE actively controls costs by targeting market median conditions for our total compensation program.

Q. How does a market-competitive total compensation package serve customers?

A. A highly qualified and experienced workforce is necessary for PGE to continue to provide customers with safe, reliable, clean, and affordable energy. If PGE was unable to compete in the job market, we would likely experience not only difficulty hiring new talent but also loss of experienced employees, which in the long-term would lead to inefficiencies and additional costs that will impact customer prices.

B. Total Labor

Q. What are the major components of PGE's total labor costs?

A. Total labor consists of the total wages, salaries, and contract labor dollars necessary to operate a utility that delivers safe, reliable, clean, and affordable energy to customers. This includes both regular and temporary PGE employees, along with contract employees.

Table 7
Total Aggregate Labor Costs by Division ($000)

	2023 Actuals (1)	2024 Budget	2025 Test Year (3)
Administrative and General	$108,841	$96,854	$105,222
Customer Accounts	$21,658	$25,405	$26,420
Customer Service	$16,091	$18,234	$17,763
Generation	$62,110	$60,132	$65,058
Transmission & Distribution	$223,921	$240,616	$255,909
Total Labor (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.

Table 8
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. What escalation rate did PGE use for labor costs in 2025?

A. The escalation rate that PGE used for non-union labor in 2025 is 4.00%,[7] which is below the Oregon Office of Economic Analysis (OEA) Wage and Salary forecasted increase in 2025 of 4.8%.[8] The 2025 escalation rate for union labor under our largest contract, Business Unit 1,

[7] Effective February 1, 2025.
[8] Oregon Department of Economic Analysis. "Oregon Economic and Revenue Forecast." March 2024. Table A.4

which serves our field crew, is currently being negotiated. For 2025 our smaller union contract, Business Unit 2, which serves our thermal fleet workers, will experience either a 3% escalation or the average rate determined by the Independent Energy Human Resources Associate (IEHRA) annual survey, whichever is greater, as laid out in the previously negotiated collective bargaining agreement.

Q. Can you briefly discuss the challenges PGE has faced in recent years regarding workforce management?

A. Yes. PGE, like many businesses, has found it increasingly difficult to find qualified candidates to fill open positions in today's challenging job market. Those difficulties apply to most of our professional positions but are especially pronounced in the technical positions that are becoming more important to PGE's operations in areas such as data sciences, engineering, energy trading and pricing, and skilled trade positions.

Q. How has PGE responded to these difficulties?

A. PGE has found it increasingly necessary over the last few years to backfill positions that are difficult to fill with contract labor. Simply because a position goes unfilled as of a certain date, does not typically mean that the associated work goes undone. Instead, to support safe, reliable, and affordable energy for our customers, we must utilize contract labor (and overtime) to fill those gaps in our workforce.

Q. If PGE did not utilize contract labor to backfill for difficult-to-fill positions what would happen?

A. If we did not utilize contract labor to backfill for difficult-to-fill positions, PGE would be at risk of having critical work that our customers rely on go uncompleted. Alternatively, an ever-increasing level of overtime from existing employees to cover these gaps will ultimately increase employee burnout and lead to higher turnover rates, further exacerbating the issue. Neither of those outcomes are compatible with the concept of an efficient and effective business that can best serve our customers with safe, reliable, and affordable energy.

Q. Has PGE made any adjustments to its test year total labor to reflect this challenge?

A. Yes. While PGE has found it increasingly difficult to find specialized talent, we still ultimately believe staffing certain positions with regular PGE employees is the best approach. Thus, the business continues to budget straight-time labor for these positions. However, to reflect the challenges PGE has faced in recent years with finding qualified candidates, which leads to the utilization of contract labor to fill temporary gaps in our workforce, we have made an adjustment that shifts $14.0 million from straight-time labor costs to contract labor costs within our 2025 test year forecast. This adjustment is based upon the last three years of budget to actual variances that PGE has seen between its straight-time labor and contract labor requirements. While the net impact of this adjustment is zero, we believe it is more reflective of our workforce composition. Table 9 below provides the three-year budget to actuals trend in PGE's O&M wages and salaries supporting this adjustment. On average over the period, PGE budgeted $14.5 million above actuals for straight-time O&M labor and budgeted $24.5 million below actuals for contract labor.

Table 9
2021-2023 Budget vs. Actuals O&M Labor Variance
($ millions)

Category	2021	2022	2023	2021-2023 Average
Straight-Time Labor Variance	$7.4	$24.6	$11.5	$14.5
Overtime Labor Variance	$(11.1)	$(3.4)	$(3.4)	$(6.0)
Contract Labor Variance	$(35.4)	$(32.2)	$(6.0)	$(24.5)
Total Labor Variance	$(39.0)	$(11.0)	$2.0	$(16.0)

Q. Has PGE made any additional adjustments to its total labor costs for 2024 and 2025?

A. Yes. To account for vacancies and/or unfilled positions, PGE has included a $11.7 million O&M reduction to 2024 budgeted and 2025 forecast wages and salaries. The figures in the tables above are net of these adjustments.

C. Incentives

Q. What is incentive pay?

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. 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. Are there any major changes to PGE's incentive pay for 2025?

A. No. The structure and format of PGE's incentive pay have not materially changed since UE 416, our last general rate case.

Q. What percentage of PGE's total compensation are incentives?

A. Incentive pay is approximately 8.0% of PGE's 2025 total compensation costs. However, because PGE has made a pre-filing adjustment to our incentives request in this case, the amount of incentive pay in our request represents approximately 2.8% of PGE's 2025 total compensation. Our pre-filing adjustment removes 50% of the cost of non-officer incentives, and 100% of officer incentives. While we voluntarily make these pre-filing reductions to lower our request in this rate case, we maintain that 100% of our incentive costs are prudent utility expenditures in support of safe, reliable, clean, and affordable energy for our customers. Table 10 below summarizes PGE's actual incentive costs for 2024 and our request for 2025.

Table 10
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.*

D. Benefits

Q. Please describe the components of PGE's total benefits.

A. There are four major components to PGE's market-competitive total benefits package: 1) health and wellness, 2) disability and life insurance, 3) post-retirement, and 4) miscellaneous benefits. These components are also typical parts of our competitors' offerings. As shown in Table 11 below, we project 2025 test year employee benefit costs of approximately $108.9 million, an increase of $9.0 million compared to 2024 budget. The leading drivers of the increase are post-retirement and health and dental plan benefit costs.

Table 11
Total Benefits ($000)

Benefits Category	**2023 Actuals**	**2024 Budget**	**2025 Test Year**
Health and Wellness	$48,544	$52,080	$56,992
Disability and Life Insurance	$1,865	$1,696	$1,862
Post-Retirement	$34,040	$43,219	$47,092
Miscellaneous Benefits	$2,827	$2,748	$2,807
Benefits Administration	$703	$193	$195
Total Benefits*	$87,980	$99,935	$108,947

* *Numbers may not sum due to rounding.*

Q. Please describe PGE's 2025 health and wellness benefits request.

A. Health and dental insurance, which makes up the majority of health and wellness expense, is forecasted $57.0 million in 2025, which is an increase of about 9.4% compared to 2024. This is based on our health and dental insurance broker's projections of market costs in 2025.

Q. Please describe PGE's 2025 post-retirement benefit request.

A. PGE's 2025 post-retirement benefits forecast of $47.1 million represents an increase of $3.9 million compared to 2024 budget. This increase is driven almost entirely by our retirement savings plan and is due to wage escalations and an increase in employee contribution match that will take place halfway through the 2024 year.

Q. Please describe the status of PGE's pension plan.

A. For 2025 PGE forecasts pension cost to be $3.9 million (or approximately $2.3 million after capitalization). We use a discount rate of 5.65% and an expected return on assets (EROA) of 6.75% in this forecast. PGE's pension plan is approximately 80% funded at the time of this testimony. For 2025 we forecast an approximate $24 million contribution[9] and believe it is likely that yearly contributions will continue for the foreseeable future.

[9] Cash contributions are not included in our request for this rate case.

V. Qualifications

Q. Ms. Mersereau, please summarize your qualifications.

A. I received a Bachelor of Arts degree in Business Administration: Human Resources and Management with a minor in Economics from Washington State University. I also hold a Senior Professional in Human Resources designation. My professional Human Resources career spans thirty-plus years and includes various roles at PGE for the last 14 years, as well as leadership positions with Hilton Hotels Corporation, Marsh USA Inc., and Waldron Consulting. I joined PGE's Human Resource (HR) organization in 2009. I've served employees in Line Operations as well as Transmission and Distribution engineers, Substation Operations, Service & Design, and Public Policy employees. In 2014, I became the Employee Services Manager, where I led HR Operations including HR Systems Reporting & Analytics, Payroll, Service Center, Health Services, and other areas. I became Vice President of HR, Diversity & Inclusion in 2016. In this position, I am responsible for leading the organization's people strategy, including talent acquisition and management, employee engagement, total rewards, health and wellness, diversity, equity and inclusion, and real estate services.

I am an active member of the community with a passion for education and workforce development. In 2017, I was appointed by Oregon Governor Kate Brown to the Oregon Workforce and Talent Development Board and currently serve as the Vice Chair. I also serve on the board of Friends of the Children-Portland.

Q. Mr. Trpik, please summarize your qualifications.

A. I joined PGE in 2023 bringing deep expertise in financial planning and analysis, capital allocation, cost management, risk management, financial systems, accounting, tax and investor communications, among other functions in the utility industry. Over my entire professional career, I have been involved with the utility industry in Finance and Accounting roles. Immediately prior to joining PGE, I served over 22 years in senior leadership positions with Exelon Corporation - one of the nation's largest utilities. These included senior vice president positions as Chief Financial Officer of Exelon Utilities as well as Chief Accounting Officer of Exelon Corporation.

I hold degrees in Finance and Accounting from Florida State University and I am a certified public accountant in Florida. Currently I am serving on the Board of Governors, School of the Art Institute of Chicago as well as the Accounting Professional Advisory Board of Florida State University.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	Summary of A&G Costs
302	PGE Insurance Policies List
303C	Summary of Insurance Costs
304	Direct and Allocated IT Charges

A&G Summary - Exhibit	Costs			
	Dec - 2021	Dec - 2022	Dec - 2023	Dec - 2024
Major Functional Area				
Accounting/Finance	12.9	14.0	14.4	13.8
Business Support Services	1.3	1.4	1.7	1.3
Corp Communications/Public Affairs	3.3	2.4	3.2	4.6
Corporate Governance	8.4	8.3	8.4	6.6
Corporate R&D	2.4	2.6	2.6	2.7
Environmental Services	3.1	2.2	1.6	2.5
Facilities/Rent	6.5	4.4	4.1	4.9
Governmental Affairs	1.6	1.8	1.7	2.0
HR/Employee Support (net of capital allocs.)	11.9	12.2	11.3	12.3
Hydro Licensing and Support				0.0
INSURANCE	15.8	17.8	18.8	19.9
IT: Direct & Allocated	15.6	17.3	16.3	15.4
Legal	11.8	8.7	6.7	9.1
Performance Management	1.0	0.3	0.1	0.3
Regulation	3.4	3.2	3.4	4.2
Security and Business Continuity	2.5	3.4	4.1	5.2
Supply Chain/Contract Services/Purchasing	2.7	3.6	3.7	3.3
Sustainability and Resource Planning	0.0	0.4	1.1	2.3
Subtotal Major Functional Area	104.2	104.0	103.3	110.4
Other A&G				
Benefits (net of capital allocs.)	54.6	40.0	42.8	53.1
Corporate Allocations (net)	(3.4)	(5.7)	(4.7)	(7.8)
Corporate Cost Reductions				(3.7)
General Plant Maint.	3.1	4.4	4.6	4.6
Incentives	44.3	42.4	44.8	48.5
LC Fees, Revolver Fees, Margin Net Int., & Broker fees	3.9	3.5	4.2	3.6
Membership Costs	2.6	2.6	2.8	3.3
Regulatory Fees	9.1	10.7	12.8	14.9
Severance	1.6	1.8	1.3	
Total Labor Loadings to A&G	0.0	0.0	(0.0)	
Total PTO to A&G	7.2	7.5	7.9	8.4
Subtotal Other A&G	123.0	107.2	116.4	125.0
Total	227.2	211.2	219.7	235.5

A&G Summary - Exhibit	Dec - 2025	Delta Change
Major Functional Area		
Accounting/Finance	14.8	1.0
Business Support Services	1.6	0.3
Corp Communications/Public Affairs	5.0	0.4
Corporate Governance	6.8	0.2
Corporate R&D	3.5	0.8
Environmental Services	2.5	0.1
Facilities/Rent	5.0	0.0
Governmental Affairs	2.2	0.2
HR/Employee Support (net of capital allocs.)	13.1	0.8
Hydro Licensing and Support	0.0	0.0
INSURANCE	21.9	2.0
IT: Direct & Allocated	18.2	2.8
Legal	9.7	0.6
Performance Management	0.3	0.0
Regulation	3.8	(0.4)
Security and Business Continuity	5.3	0.1
Supply Chain/Contract Services/Purchasing	3.5	0.2
Sustainability and Resource Planning	1.8	(0.5)
Subtotal Major Functional Area	119.1	8.6
Other A&G		
Benefits (net of capital allocs.)	57.9	4.8
Corporate Allocations (net)	(8.8)	(1.0)
Corporate Cost Reductions	(3.4)	0.3
General Plant Maint.	4.2	(0.4)
Incentives	17.9	(30.6)
LC Fees, Revolver Fees, Margin Net Int., & Broker fees	3.5	(0.1)
Membership Costs	3.5	0.2
Regulatory Fees	16.6	1.7
Severance		
Total Labor Loadings to A&G	2.4	2.4
Total PTO to A&G	8.8	0.3
Subtotal Other A&G	102.6	(22.4)
Total	221.7	(13.8)

PGE's Insurance Policies

Insurance Policy	Description
All Risk Property	PGE's main All-Risk property insurance insures PGE's property such as power plants, substations, office buildings, etc. from "all-risks" of direct physical loss or damage (including boiler and machinery), subject to policy exclusions, caused by perils such as fire, explosion, lightning, wind, ice, hail, flood, earthquake, and certain acts of terrorism. This policy specifically excludes coverage for PGE's transmission and distribution property as well as PGE's renewable projects. Under this program PGE maintains coverage limits of $600 million with a $5.0 million deductible.
Director's and Officer's Insurance	Directors and Officers (D&O) Liability Insurance shields PGE's directors and officers against the normal risks associated with managing the business. The insurance premiums requested in this case are reasonable expenses that are necessary to attract and maintain qualified and competent directors and officers and they provide a direct benefit to PGE's customers. Currently PGE purchases $140 million in D&O insurance limits with $2 million deductible. No deductible applies to Side A, or individual coverage. The limits purchased are reasonable, necessary and consistent with the standard practice of the utility industry. The lack of an appropriate level of D&O insurance would make it difficult for PGE to hire qualified and competent people for positions at the director and officer level. In addition, lack of appropriate D&O limits would provide a significant motivation for our experienced directors and officers to seek employment elsewhere. Subjecting the Company to the potential of such adverse outcomes is not in the best interest of PGE's ratepayers.
General & Auto Liability	General and Auto Liability insurance covers PGE's legal liability from claims resulting from bodily injury or property damage arising out of PGE's operations, including the use of company vehicles. Given PGE's contact with its customer's premises and the dangerous nature of its operations, this insurance is of paramount importance. PGE maintains coverage limits of $210 million with a $5 million self-insured retention.
Nuclear	PGE is required by the United States Nuclear Regulatory Commission to maintain Nuclear Liability coverage for the on-site storage of its spent fuel until such time that the radioactive materials have been removed from the Trojan site. The coverage consists of three policies: (1) The Facility Form insuring PGE's legal responsibility for damages because of bodily injury, property damage, or covered environmental clean-up costs caused by the Nuclear Energy Hazard during the policy period and reported within ten years of the policy termination date. (2) Master Worker insuring PGE's legal obligation to pay as damages because of bodily injury sustained by a "worker" and caused by the nuclear energy hazard. "Worker" refers to a person who is or was engaged in nuclear related employment; (3) Suppliers and Transporters covering incidents caused by radioactive waste materials stored either temporarily or permanently at off-site locations not owned/operated by the insured.
Fiduciary	Fiduciary Liability insurance provides protection for officers and employees for both breach of fiduciary duties and other wrongful acts in the administration of employee benefits programs. This program is made up of total limits of $50 million with a $0.25 million self-insured retention.
Aviation (Helicopter)	This policy insures the helicopter's hull value from physical damage and provides $20 million of liability coverage in operating the aircrafts during PGE's aerial patrol operations.
Aviation (Unmanned Aircraft Systems)	This policy provides $5 million of liability coverage for operating Unmanned Aircraft Systems (also known as 'Drones') while conducting aerial patrols and inspections.
Cyber	The policy has several insuring agreements, providing coverage for: (1) damages and claims expenses due to theft, loss or unauthorized disclosure of personally identifiable non-public information or third party corporate information, (2) costs incurred to comply with a breach notification law, and (3) claims expenses and penalties in the form of a regulatory proceeding resulting from the violation of a privacy law such as HIPPA or FTC. PGE purchases a limit of $30 million with a $1.0 million self-insured retention.
Fidelity & Crime	Insures losses incurred by PGE or its employee benefit plans as a result of the dishonest acts of employees, including embezzlement, forgery or the theft of money or securities. The policy has a $10 million limit and $0.5 million deductible. This coverage is typically excluded under most All-Risk Property policies and must therefore be purchased under separate cover.
Excess Workers' Compensation	The State of Oregon requires PGE to maintain Workers' Compensation coverage to protect itself from catastrophic losses to employees arising out of and in the course of employment. This coverage sits above PGE's self-insured Workers' Compensation program and is subject to a $2 million self-insured retention. PGE must also maintain Workers' Compensation coverage in states outside of Oregon where it has employees. The policy provides statutory coverage for employees outside of OR, WA, ND, OH, and WY.
Sabotage & Terrorism	Insures buildings and contents against physical loss or physical damage. Insures damages and claims expenses that the Company may become legally liable to pay for bodily injury, property damage and/or defense costs caused by an Act or series of Acts of Terrorism and/or Sabotage. PGE maintains coverage limits of $500 million for property and $200 million for liability subject to a $0.25 million deductible.
Surety Bonds	In the course of doing business PGE must procure and maintain a number of Surety bonds throughout the year. These bonds allow PGE to do work for various state and city governments and agencies and are a requirement for maintaining a form of collateral for self-insuring PGE's Workers' Compensation obligations.

Exhibit 303 contains confidential information and is subject to

General Protective Order 23-132

PGE
Live Scenario

Not Scaled

IT Exhibit	a-Dec - 2021	a-Dec - 2022	a-Dec - 2023
Generation			
IT Direct	15,000	18,100	
IT Allocated	7,589,446	6,848,962	6,613,857
Subtotal Generation	**7,604,446**	**6,867,062**	**6,613,857**
Power Ops			
IT Direct	2,451,677	3,468,668	2,490,462
IT Allocated	5,738,413	5,849,995	5,491,908
Subtotal Power Ops	**8,190,091**	**9,318,663**	**7,982,370**
Transm.			
IT Direct	1,198,381	966,619	1,810,902
IT Allocated	714,644	730,606	376,278
Subtotal Transm.	**1,913,025**	**1,697,225**	**2,187,181**
Distr.			
IT Direct	4,801,743	5,878,009	6,555,653
IT Allocated	13,993,439	6,936,204	5,842,393
Subtotal Distr.	**18,795,182**	**12,814,213**	**12,398,046**
Cust Service			
IT Direct	98,726	260,273	96,987
IT Allocated	3,015,264	5,118,746	4,670,042
Subtotal Cust Service	**3,113,990**	**5,379,019**	**4,767,029**
Cust Accounts			
IT Direct	16,673,435	12,575,244	12,855,875
IT Allocated	12,845,758	10,135,274	9,370,808
Subtotal Cust Accounts	**29,519,192**	**22,710,518**	**22,226,683**
A&G			
IT Direct	2,716,438	6,045,499	5,826,631
IT Allocated	15,218,119	12,976,405	12,211,381
Subtotal A&G	**17,934,558**	**19,021,904**	**18,038,012**
Total			
IT Direct	27,955,401	29,212,412	29,636,511

PGE
Live Scenario

Not Scaled

IT Exhibit	a-Dec - 2021	a-Dec - 2022	a-Dec - 2023
IT Allocated	59,115,083	48,596,191	44,576,668
Subtotal Total	**87,070,484**	**77,808,603**	**74,213,179**

PGE
Live Scenario

Not Scaled

IT Exhibit	Dec - 2024	Dec - 2025	Delta (Test Year - Base Year)
Generation			
IT Direct	80,000	80,824	824
IT Allocated	7,730,171	8,425,520	695,349
Subtotal Generation	**7,810,171**	**8,506,344**	**696,173**
Power Ops			
IT Direct	3,657,467	4,441,116	783,650
IT Allocated	6,621,720	7,090,937	469,217
Subtotal Power Ops	**10,279,187**	**11,532,053**	**1,252,866**
Transm.			
IT Direct	2,456,883	2,576,287	119,404
IT Allocated	699,221	834,888	135,667
Subtotal Transm.	**3,156,104**	**3,411,175**	**255,071**
Distr.			
IT Direct	5,861,436	7,339,654	1,478,218
IT Allocated	4,485,664	5,693,529	1,207,865
Subtotal Distr.	**10,347,100**	**13,033,183**	**2,686,083**
Cust Service			
IT Direct			
IT Allocated	4,106,006	4,525,715	419,709
Subtotal Cust Service	**4,106,006**	**4,525,715**	**419,709**
Cust Accounts			
IT Direct	13,536,275	13,051,303	(484,972)
IT Allocated	11,176,961	11,948,278	771,317
Subtotal Cust Accounts	**24,713,236**	**24,999,581**	**286,344**
A&G			
IT Direct	(2,632,605)	(153,147)	2,479,458
IT Allocated	15,899,580	17,181,628	1,282,047
Subtotal A&G	**13,266,975**	**17,028,481**	**3,761,506**
Total			
IT Direct	22,959,456	27,336,037	4,376,582

PGE
Live Scenario

Not Scaled

IT Exhibit	Dec - 2024	Dec - 2025	Delta (Test Year - Base Year)
IT Allocated	50,719,323	55,700,494	4,981,171
Subtotal Total	**73,678,779**	**83,036,531**	**9,357,753**

PGE
Live Scenario

Not Scaled

IT Exhibit	Annual % Delta (Test Year - Base Year)
Generation	
IT Direct	1.0%
IT Allocated	9.0%
Subtotal Generation	8.9%
Power Ops	
IT Direct	21.4%
IT Allocated	7.1%
Subtotal Power Ops	12.2%
Transm.	
IT Direct	4.9%
IT Allocated	19.4%
Subtotal Transm.	8.1%
Distr.	
IT Direct	25.2%
IT Allocated	26.9%
Subtotal Distr.	26.0%
Cust Service	
IT Direct	
IT Allocated	10.2%
Subtotal Cust Service	10.2%
Cust Accounts	
IT Direct	(3.6%)
IT Allocated	6.9%
Subtotal Cust Accounts	1.2%
A&G	
IT Direct	(94.2%)
IT Allocated	8.1%
Subtotal A&G	28.4%
Total	
IT Direct	19.1%

PGE
Live Scenario

Not Scaled

IT Exhibit	Annual % Delta (Test Year - Base Year)
IT Allocated	9.8%
Subtotal Total	12.7%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Transmission and Distribution (T&D)

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Larry Bekkedahl
Benjamin Felton

February 29, 2024

Table of Contents

I. Introduction

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

A. My name is Larry Bekkedahl. I am employed by PGE as the Senior Vice President of Strategy and Advanced Energy Delivery.

My name is Benjamin Felton. I am employed by PGE as the Executive Vice President and Chief Operating Officer. 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 discuss the needed investments to meet customer demand, maintain safety standards, and improve the resilience of our system. Our testimony provides Transmission and Distribution (T&D) capital expenditures from January 1, 2024, through December 31, 2024, and incremental operations and maintenance (O&M) activities and costs for the 2025 test year. We also provide additional information on Routine Vegetation Management (RVM), Utility Asset Management (UAM), the Level III Storm Accrual Mechanism, and PGE's Virtual Power Plant (VPP). Finally, this testimony proposes a new Investment Recovery Mechanism (IRM) for some of PGE's capital projects.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II – Overview & Summary
- Section III – T&D Capital Additions
- Section IV – 2025 O&M
- Section V – Investment Recovery Mechanism
- Section VI – Qualifications

II. Overview and Summary

Q. Please summarize your request for this filing.

A. We request that the Commission find PGE's investments in T&D prudent and that the Commission approve PGE's 2025 forecast of $214.9 million in T&D O&M costs, excluding IT-related expenses, which are discussed in PGE Exhibit 300. This forecast represents a $20.3 million increase from the 2024 budget primarily due to increasing costs associated with contract labor for RVM, increased work volume and contract labor for UAM, and program development for VPP. We also request that the Commission approve PGE's proposed IRM, as described in Section V.

Q. How would approval of PGE's request benefit customers?

A. Improvements in T&D and grid modernization will benefit customers by modernizing and securing the grid and its operations for enhanced reliability, especially by leveraging distributed energy resources. Customers will benefit from projects that support additional capacity and flexibility on the system to meet new and growing customer load, specifically through the implementation of customer solutions that enable electrification of transportation and buildings. Approval of PGE's request helps accelerate decarbonization while maintaining a reliable and resilient integrated grid. It increases safety of the system that serves customers through work performed to meet National Electric Safety Code (NESC), North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) requirements, and all other applicable standards.

III. T&D Capital Additions

Q. Please summarize the T&D and grid modernization capital additions (net of Wildfire Mitigation capital) forecast to be placed in service from January 1, 2024, through December 31, 2024.

A. PGE is continuing to invest in grid modernization, additional substations, and enhanced distribution systems, which will allow us to continue to meet customer demands while maintaining resiliency and safety. We forecast investments of $766.6 million in total T&D and grid modernization capital additions to be placed in service from January 1, 2024, through December 31, 2024. Table 1 shows a breakdown of these capital projects.

Table 1
T&D Capital Additions ($ millions)

Category	Additions
Poles and Wires	$372.7
Substation	$256.7
Grid Modernization	$90.7
Other	$44.5
Communications	$2.0
Total	$766.6

Q. Does PGE have a list of T&D and grid modernization projects that will be included in this general rate case?

A. Yes, the list of projects can be found in PGE Exhibit 401.

Q. Please provide a brief overview of the investments made in poles and wires.

A. Poles and wires investments include:

- $155.8 million in poles/towers/fixtures, with over three-quarters ($128.6 million) of this invested in our ongoing overhead distribution replacement work, such as pole and cross-arm replacements on distribution assets, as identified through our overhead Facilities Inspection and Treatment to the National Electric Safety Code (FITNES) program. Other work includes T&D asset relocation, transmission line clearance mitigation, and overhead transmission FITNES.

- $85.4 million in projects to meet customer needs. Projects include customer service connections for new residential and commercial customers, including installing underground and overhead lines, conductors, transformers, vaults, and metering; lighting installations, removals and upgrades for municipalities, property developers, and residential and commercial customers; and purchasing and installing customer meters.
- $56.0 million for reconductor or conversion projects, as well as a transmission line.
- $34.2 million primarily to replace or upgrade underground cable, driven primarily by the age of the cable, to enhance reliability and mitigate the probability of failures that could cause injury or damage.
- $19.8 million in blanket T&D projects focused on system construction and upgrades, such as non-FITNES replacement of distribution facilities due to deterioration, including line switches, transformers, pole-mounted equipment such as regulators and reclosers, and underground or overhead lines.
- $15.1 million for emergency distribution asset replacements (e.g., poles, switches, transformers) due to major storms, outages, or damage caused by third parties (e.g., car hits pole).
- $6.5 million in roadway improvement projects due to civil improvement projects, such as state or city road widening improvement projects which require us to move or replace poles along the roadway.

Q. Please provide a brief overview of the investments made in substations.

A. There is $256.7 million in substation investments to support reliable service to all customers (residential, commercial, and industrial) across our service territory and to maintain compliance with NERC standards. Investments are made based on the existing and forecasted needs of the local area and the overall system; this includes both building new substations and upgrading existing substations. The projects that exceed $10 million include the Evergreen, Tonquin, Reedville, Shute, Grizzly, and Memorial substations. All of these substation projects were recommended as best solutions as part of our multi-phased distribution planning process.

Q. Is there any further information available for these capital projects?

A. Descriptions of the 20 largest capital projects, each of which will be in service by December 31, 2024, at or above $10 million, are provided as a part of PGE's Exhibit 402. Project justification forms for these projects, which provide additional details, are found in Exhibit 403. These projects collectively represent approximately 82% of the total T&D capital additions PGE is proposing in this rate case.

Q. Briefly describe PGE's grid modernization initiative.

A. PGE's grid modernization is a multi-year, multi-faceted initiative to evolve the grid through the integration of new technologies and enhanced sensors and computing solutions which enables bidirectional flow of energy. Grid modernization provides improved operator awareness, integration, and control of transmission and distribution equipment, including utility or customer-owned distributed energy resources (DERs) and flexible loads. Customers benefit from the development of a bidirectional grid that is reliable, resilient, and secure, and that also supports decarbonization efforts. Additional information about PGE's grid modernization framework and initiatives is provided in our Distribution System Plan (DSP).[1]

[1] *See* https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning.

IV. 2025 O&M

Q. Please summarize the T&D O&M costs for the 2025 test year.

A. As shown below in Table 2, T&D O&M costs are forecast to be $214.9 million in 2025. Information technology (IT) costs have been separated and are discussed in PGE Exhibit 300. The 2025 forecast represents a $20.3 million or 10.5% increase from PGE's 2024 budget. As stated in PGE Exhibit 200, comparing 2024 to 2025 is most appropriate as the 2024 budget is in line with the final costs approved in PGE's 2024 general rate case by Commission Order No. 23-386 in Docket No. UE 416 (UE 416).

Table 2
T&D and Grid Modernization O&M ($ millions)

	2023 Actuals	2024 Budget	2025 Forecast	2024-2025 Variance	2024-2025 % Change
Labor	$80.5	$89.2	$98.6	$9.4	10.5%
Non-Labor	$80.4	$105.3	$116.2	$10.9	10.4%
Subtotal	$160.8	$194.5	$214.9	$20.3	10.5%
IT	$14.6	$13.5	$16.4	$2.9	21.8%
Total O&M*	$175.4	$208.0	$231.3	$23.3	11.2%

**May not sum due to rounding*

Q. Are there any costs related to T&D that are not included in Table 2?

A. Wildfire mitigation costs have been removed due to the establishment of the annual automatic adjustment clause for wildfire mitigation (i.e., PGE Schedule 151). This lowers overall O&M costs as presented from 2023 actuals through the 2025 test year.

Q. Has PGE included any adjustments for meals and entertainment in its 2025 O&M forecast?

A. Yes. We have reduced the 2025 forecast for meals and entertainment by $0.4 million, which is approximately 50% of the costs incurred within T&D during 2023.

Q. What are the major drivers behind 2025 non-labor O&M?

A. When comparing the 2025 non-labor forecast to 2024 non-labor, the biggest drivers identified are RVM, UAM, and VPP. In addition, PGE is updating the ten-year average for its Level III Outage Accrual Mechanism, which accounts for a minor change (approximately $0.2 million) to O&M.

A. Routine Vegetation Management

Q. What is driving the increase in RVM?

A. The incremental O&M expense for RVM from 2024 to 2025 is $4.8 million, driven primarily by the increased cost of contract labor to remove vegetation.

Q. What are the incremental O&M costs for RVM in 2025 compared to 2024?

A. In 2024, PGE has budgeted to spend a total of $53.2 million, largely in line with the RVM forecast presented in UE 416. In 2025, PGE forecasts $58.1 million of spend for the baseline of the mechanism, which is a 9.1% increase over 2024 levels. This increase is largely due to contract rate escalations from increased market pressures and four additional full-time employees.

Q. What is PGE's vegetation management strategy?

A. Vegetation management is critical to ensuring a safe, reliable, and resilient system. Our RVM program falls under Oregon Administrative Rules (OAR) Chapter 860, Division 24 Safety Standards. Under the RVM program, PGE's entire system is inspected on a cyclical basis.

Q. Please describe PGE's RVM program.

A. Our RVM program has three primary functions: 1) line clearance compliance, 2) construction support, and 3) outage/storm response.

Our line clearance compliance and FITNES work is driven by Public Utility Commission of Oregon (OPUC) Division 24 Safety Standards. We target trimming trees across one-third of our system each year. PGE manages approximately 2.4 million trees across our service territory.

We perform vegetation management work in support of construction, maintenance, or repair projects, such as pole replacements, reconductors, and new line construction. Our outage and storm response work manages vegetation during and after a wind, ice, snowstorm, or other major outage event. This work may occur at any time of day or night and is supported by on-call, dispatched vegetation management internal and external labor.

Q. Has there been interest in potential changes to the RVM mechanism?

A. Yes. In UE 416, the Commission approved the sixth partial stipulation authorizing PGE to establish a balancing account for RVM expenses with a baseline value set at the amount PGE requested in its initial filing.[2] The parties to the sixth partial stipulation also agreed to engage in a subsequent process to establish metrics that can be applied going forward to PGE's RVM spending on the annual under-or-over-collection. The parties have yet to engage in discussions about potential metrics, but PGE is developing possible metrics that can reasonably be identified, measured, and associated with the amounts of under-or-over collections.

B. Utility Asset Management

Q. What is driving the increase in UAM?

A. This increase is being mainly driven by additional FITNES work expected in 2025, since increased labor costs and aging infrastructure are causing increased costs.

[2] *See* OPUC Order No. 23-386

Aging infrastructure is resulting in an uptick in failures during inspections, which result in additional corrections.

Q. What are the incremental O&M costs for UAM in 2025 compared to 2024?

A. In 2024, PGE expects to spend $26.0 million. In 2025, PGE expects to spend $31.8 million, which is an increase of 22.4% over 2024's budget. This is primarily due to increased FITNES work related to inspections and corrections, which have been increasing in cost due to contract labor escalations and an increase in the amount of work necessary to maintain a safe and reliable system.

Q. Please explain the increasing costs for FITNES inspections.

A. PGE is currently starting our seventh year of a ten-year cycle of regulatorily required inspections.[3] There is a program to inspect PGE's underground units, and PGE needs to inspect approximately 10,200 units per year to stay on cycle. In addition to escalating the rate of inspections to ensure that PGE can meet its goals for the 10-year cycle, PGE is continually facing increased contract labor costs; whereas 2024 is a bargaining year and new labor rates are unknown, 2023 started at inflation above 6%, and the current inflation rate is approximately 3.4%. There is also a program to inspect PGE's overhead units (poles), and we inspect approximately 32,000 poles each year. Similar to underground inspections, PGE has been facing contract labor increases for overhead inspections. If PGE fails to fund our inspection projects, we risk not completing our 10-year cycle inspections and the safety and reliability of the system could be at risk.

[3] *See* ORS Section 757.035; OAR 860, Division 24 Safety Standards.

Q. Please explain the increasing costs for FITNES corrections.

A. PGE is starting our fifth year of a ten-year cycle of national electrical code-required corrections.[4] The FITNES program corrects for PGE inspection identified national electrical code conditions that could result in future physical harm or property damage incidents. There are three primary projects of note: Tape & Shape, O&M Work Orders, and Customer Side Corrections.

- The Tape & Shape program in 2023 included more than 64,000 corrections, which is above the average of around 40,000 corrections. This is due to the grid area inspected in 2022 being PGE's second most dense area in terms of poles and services feeding customers. For example, this grid area has a ratio of 6.2 service drops per pole (power service providing power to a single meter) as opposed to an average 1.7 service drops per pole in a standard map grid. In 2024, PGE expects to inspect our most dense grid area, which will result in an above-average amount of corrections to be completed in 2025.
- FITNES O&M Work Orders grew in 2023 and continue to increase in 2024. PGE has adjusted O&M work order scope and schedule, to optimize the correction work related to budget but PGE still has remaining O&M Work Orders from 2023 and is expecting around 4,000 more work orders that will need to be completed in 2024. Ultimately, this project is scheduled to complete approximately 4,500 work orders each year.
- Since its inception in 2018, PGE's Customer Side Corrections project has seen greater than a 50% increase in cost of local electrician labor and materials to repair

[4] Ibid.

customer's service entrance wires and customer meter bases. PGE's customers that have unsafe conditions to their service bear the bulk of these costs, although some low-income or fixed-income customers receive assistance from PGE directly through this project's funding or through local non-profit agencies where PGE facilitates.

Similar to inspections, correctional work is essential for PGE to complete in a timely manner to maintain safety and reliability in the system.

C. Level III Outage Accrual Mechanism

Q. Does PGE have a mechanism to address restoration costs associated with major outages?

A. Yes. Pursuant to Commission Order No. 10-478 (Docket No. UE 215), PGE accrues and recovers an annual amount based on a ten-year moving average of restoration costs related to major outages, or more precisely, Level III events. The accrued amounts are recorded to a reserve account to which actual Level III restoration costs are charged as they are incurred. To qualify as a Level III event, one of the following criteria must be met:

- Impacts at least 50,000 customers;
- Qualifies for Institute of Electrical and Electronics Engineers (IEEE) Major Event Day exclusion;[5] or
- Renders several substations and feeders out of service.

Additionally, pursuant to Commission Order No. 22-129, PGE's Level III outage accrual mechanism has been updated to allow for a negative balance of up to two times the ten-year average accrual. This negative balance is set as a hard cap and amounts beyond this cap are not to be included in the mechanism.

[5] An IEEE Major Event Day exclusion is a day in which our daily System Average Interruption Duration Index (SAIDI) exceeds a threshold value. In 2021, the T_{med} was 4.80 minutes. If our accrued daily SAIDI minutes exceed the threshold, that day is considered a major event day (MED) and is analyzed separately from events occurring on days that are not MEDs for PGE's annual reliability reports, pursuant to OAR 860-023-0151.

Q. Is PGE proposing any changes to the current Level III Outage Accrual Mechanism?

A. No. We are not requesting any changes to PGE's Level III Outage Accrual Mechanism in this case.

Q. Are you updating the annual accrual based on the most recent ten-year moving average of restoration costs?

A. Yes. Although PGE did not experience any significant storms during 2023, the current ten-year moving average slightly increased by approximately $0.1 million resulting in an updated annual accrual of approximately $6.4 million. This increase is summarized in PGE Exhibit 404.

D. Virtual Power Plant

Q. What is a Virtual Power Plant?

A. VPP is a production resource comprised of Distributed Energy Resources (DERs) and flexible loads that are managed through technology platforms to provide grid and power operations services. Additionally, Enterprise Distributed Energy Resources Management System (DERMS) initial release will provide scalable DER registration and grouping capabilities as a part of the VPP.

Q. What are the incremental O&M costs for VPP in 2025?

A. The incremental cost increase from 2024 to 2025 forecast is approximately $4.0 million. This incremental change is being driven by VPP initial startup costs including the hiring of new staff, program development costs including IT resources, and training and development expenditures. These startup costs are critical to successful implementation of key DERMS project milestones in the next three years. As identified in our 2023 Integrated Resource Plan

(IRP), DER and other flexible load growth is integral to meeting our capacity and energy needs over the next five to ten years.

Q. What resource types can be orchestrated through the PGE VPP?

A. PGE's VPP orchestrates DERs and flexible loads. DERs include generation resources, such as distribution-connected solar and customers' dispatchable standby generators (DSG), as well as energy storage resources, such as batteries and electric vehicles. Flexible loads include demand response and other customer programs.[6] Resources orchestrated through the VPP may be connected at the transmission or distribution level, sited on the utility or customer side of the meter, acquired through PGE procurement programs, or developed through voluntary customer action.

Q. What benefits does the VPP provide to customers?

A. The evolution of our system includes significant growth of DERs and flexible loads; to realize their full potential for customers, these new resources must be integrated into the system and orchestrated to provide grid services.[7]

When orchestrated through a VPP platform, DERs and flexible loads contribute to decarbonization, advance customer and community energy resilience, promote customer engagement with the energy system, and unlock additional grid services that enable a dynamic bi-directional system.

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[6] Demand response programs will be integrated with and dispatched via the VPP, but the VPP will not have to interface with participating customers individually. Widespread customer enrollment and communications will continue to be managed through PGE customer programs.

[7] Our DER and flexible load forecast methodology and results are presented in Part 2 of our Distribution System Plan. *See*, https://assets.ctfassets.net/416ywc1laqmd/46I2n65SyTv3TUMMdq1l55/a993aebb7b7a84ebd3209d798454a33a/DSP_Part_2_-_Chapter03.pdf

Ultimately, the goal of our VPP is to provide value by utilizing the significant number of DERs and flexible loads by operating a platform to orchestrate them collectively, and with a higher degree of flexibility than they are able to achieve individually.

Q. Is PGE's VPP approach informed by utility industry best practices?

A. Yes. PGE's approach is informed by ongoing conversations with peer utilities and industry leaders. PGE utilizes industry forums such as the Electric Power Research Institute (EPRI), Smart Energy Power Alliance (SEPA), Edison Electric Institute (EEI), GridWise Alliance, and Stanford Bits & Watts. PGE engaged in informal discussions with utilities in California, Hawaii, and across the United States to understand their approaches and lessons learned. Additionally, in 2022, PGE engaged West Monroe Partners, a consulting company that has advised numerous utilities in the United States and globally on grid modernization programs, to benchmark other utility efforts and support development of PGE's VPP approach.

V. Investment Recovery Mechanism

Q. Please describe the Investment Recovery Mechanism (IRM).

A. PGE is proposing a mechanism that will allow for recovery outside of a general rate case of certain vital investments made to maintain the safety, reliability, and resilience of PGE's current energy delivery system. These are investments that are necessary and beneficial to all customers as the electric grid continues to evolve and advance. The use of this mechanism would provide for a pathway to avoid annual rate cases. Currently, costs associated with these essential, ongoing investments in PGE's system can only be recovered through a full general rate case.

Q. In lieu of this mechanism, did PGE consider the filing of a multi-year rate case to avoid annual rate case filings?

A. Yes, PGE did review the possibility of filing a multi-year rate case. We did not file one for two reasons. First, there is no track record of multi-year rate case filings in Oregon, and, therefore, there are no meaningful guiding principles from previous Commission-approved multi-year rate cases for PGE to replicate. Absent such history, we knew it would be challenging for the Commission and stakeholders to support a multi-year rate case without sufficient time to consider the mechanics of such a plan. Second, because PGE's year-over-year growth going forward is driven by capital investments to maintain and strengthen a reliable and resilient energy delivery system, it is unclear how a multi-year rate proceeding could allow for the inclusion of this capital growth.

Q. You stated that PGE's capital additions are causing the need for rate cases. Why are PGE's capital additions growing at a higher rate than in the past?

A. While PGE has historically invested annually in projects to maintain the resilience and reliability of our system, we have recently seen an increase in investments needed to meet long-term imperatives, such as projects that will reduce emissions or comply with safety and reliability requirements, such as those established by NESC and NERC.

Q. What is PGE proposing to include within the IRM?

A. We are proposing that investments made by PGE to sustain our current business and customer base be included within this mechanism. These are investments to meet and maintain safety and reliability standards, including our overhead and underground FITNES program investments required under the Division 24 Safety Standards Rules. It would also include investments for environmental compliance and to replace aging substation assets necessary for maintaining safe, reliable energy delivery to our current customers. These projects are not associated with obtaining additional revenue through load growth or strategic investments to expand our business.

Q. Please identify the projects that would be included in the mechanism at this time.

A. A list and brief description of the projects and the forecasted investment through 2028 is provided as PGE Exhibit 405.

Q. Are you requesting recovery of all forecasted investments made by PGE?

A. No. As stated above, no project associated with obtaining additional revenue through load growth is included in this mechanism. We believe this mechanism should represent only projects that are most beneficial to the safety and reliability of PGE's system for its current customers.

Q. How does PGE propose to structure the timing for this mechanism?

A. Each year, in August, PGE would file a tariff update reflecting changes in capital for the current full calendar year. This update would include both additions and accumulated depreciation for the included assets. This would represent actual and anticipated additions through the end of the calendar year, which is consistent with how rate base has been calculated for rate cases for nearly a decade. This would then allow for a review of the projects from August to December, with a price effective date of January 1 the following year.

Q. Does PGE request this mechanism in perpetuity?

A. No. We propose that this mechanism sunset on December 31, 2030. Based on PGE's current and anticipated capital forecasts, this mechanism will address investments that will be significant drivers for future general rate cases through 2030. However, over the long term, PGE would like to work with parties and the Commission to potentially establish a multi-year rate case process that could also be used as a tool for cost recovery in lieu of a time-limited mechanism such as the proposed IRM.

Q. How does your proposal benefit customers?

A. This proposal benefits customers by providing a tool to recover a limited set of costs outside of a full general rate case involving potential broad cost updates. By avoiding full rate cases, when possible, through the use of this mechanism, customers benefit because PGE is effectively obligated to manage its O&M costs to stay within the budget established in the last general rate case. This mechanism allows PGE to have a modest increase related to these targeted and important investments that benefit customers while staying out of larger rate cases that would inherently include growing O&M expense and other rate base increases.

VI. Qualifications

Q. Mr. Bekkedahl, please describe your qualifications.

A. I received a Bachelor of Science Degree in Electrical Engineering from Montana State University. I serve on the Electric Power Research Institute's Research Advisory Board, and serve as a board member for GridWise Alliance, Advisory Board for Pacific Northwest National Labs, and the Stanford University Bits & Watts advisory council. My employment with PGE started in August 2014 as Vice President of Transmission and Distribution. Prior to that, I served as Senior Vice President for Transmission Services at the Bonneville Power Administration (BPA) and have held other leadership and management positions at BPA, Clark Public Utilities, PacifiCorp, and Montana Power Company. I also have international utility experience gained by participating in a six-month exchange program with Hokuriku Electric Power Company in Toyama, Japan, developing hydro projects in the Philippines, and participating in United States Agency for International Development exchange projects in Bangladesh, the Republic of Georgia, and the Philippines.

Q. Mr. Felton, please describe your qualifications.

A. I received a Bachelor of Science Degree in Business Management from the University of Phoenix and a Master of Arts in Business Administration and Management from Spring Arbor University. I have also completed various executive leadership development programs, including the Executive Leadership Development and NISOURCE Talent Development Program through partnership programs at Michigan State University and University of Wisconsin-Madison.

My employment with PGE started in April 2023 as Executive Vice President and Chief Operating Officer. I have more than 30 years of experience in the utility industry holding various leadership and executive positions at multiple utilities across the country.

Prior to joining PGE, I served as Senior Vice President of Energy Supply at DTE Energy, overseeing the operation and maintenance of the company's non-nuclear electric generation, including engineering and capital projects, Generation Optimization, Corporate Fuel Supply, NERC Compliance and Security Governance organizations. I also served as Senior Vice President of Electric Operations at NIPSCO a subsidiary of NiSource, where I oversaw the company’s electric power delivery and generation operations, including transmission and distribution, system control, field operations, vegetation management, construction, and safety, along with the operation of the company’s electric generation fleet, which included coal, natural gas, and hydroelectric generation capacity.

Additionally, I served as the Vice President of Power Delivery at NIPSCO, where I was responsible for the entire electric system, including transmission and distribution operations, maintenance, and power restoration. Prior to that, I served as the Executive Director of Electric System Operations at Consumers Energy where I oversaw the company’s sub-transmission and distribution lines, and substations, along with holding various other leadership roles focused on electric system operations.

I serve on the Association of Edison Illuminating Companies (AEIC) Board of Directors and the Electric Power Research Institute (EPRI) National Response Executive Committee (NREC). I have served on the boards of MEA Energy Association and ReliabilityFirst Corporation.

List of Exhibits

PGE Exhibit	Description
401	UE 435 Project List
402	Large Project Descriptions
403C	Project Justification Forms
404	Level III Outage Accrual Mechanism Workpaper
405	Investment Recovery Mechanism Projects

Exhibit 401 - UE 435 Project List

Project #	Project Name	In Service Amounts	
P36666	Build Evergreen Substation	**$**	**137,661,069**
P37218	OH FITNES Distribution	**$**	**128,561,087**
P36954	Tonquin Substation Build	**$**	**41,889,684**
P37302	Horizon-Keeler BPA #2 230kV Line	**$**	**39,472,130**
P36101	Substation Communication Upgrade	**$**	**30,204,142**
P36728	Coffee Creek - Energy Storage	**$**	**29,302,146**
P14628	Replace Failed Underground Cables	**$**	**25,262,098**
P35890	Purchase Distribution Transformers	**$**	**20,141,425**
P35925	Dist. Customer Line Construction II	**$**	**19,463,178**
P37214	Dist. Customer Line Construct III	**$**	**19,388,446**
P37266	Reedville Substation Rebuild	**$**	**16,954,513**
P36916	Harborton Reliabilty Ph2 - 115kV	**$**	**16,540,811**
P37048	Outage or Emergency Replacement	**$**	**15,079,836**
P37366	Shute WJ1 and WJ2 Upgrade	**$**	**14,898,016**
P36953	Memorial Substation Build	**$**	**13,727,218**
P37421	Foreign Utility Blanket	**$**	**13,203,400**
P36770	Street & Area Light Construction	**$**	**11,917,095**
P36422	Evergreen Property Land Purchase	**$**	**11,671,018**
P35892	Purchase Customer Meters	**$**	**11,538,208**
P37213	Distribution System Construct III	**$**	**11,282,623**
P37046	T&D Asset Relocation	**$**	**9,428,628**
P37061	OH FITNES Transmission	**$**	**7,619,522**
P35924	Distribution System Construction II	**$**	**7,047,612**
P36501	Integrated Operations Center - IOC	**$**	**6,793,182**
P36932	Marquam Cap Addn - Terwilliger	**$**	**6,788,674**
P36522	Distribution Automation	**$**	**6,755,875**
P37211	Substation Cap Rplcmts 2022-2024	**$**	**6,205,474**
P37370	Salem Smart Power Center Repower	**$**	**5,885,568**
P37819	Shute Feeder Reconfiguration	**$**	**4,726,093**
P39011	Transmission Delivery Grow - Reserv	**$**	**4,509,758**
P37049	Dist. Crews Truck Stock Materials	**$**	**3,978,000**
P37201	Oregon City Line Center Project	**$**	**3,638,999**
P37321	PGE / DTNA HD Charging Phase 2	**$**	**3,544,322**
P37275	Project Basie	**$**	**3,274,527**
P35484	Repl Trans Structures & Insulators	**$**	**3,053,038**
P39040	ODOT Donald Aurora Interchange	**$**	**2,772,386**
P36913	Transm Line Clearance Mitigation	**$**	**2,583,362**
P37494	Livefront Switch Replacements	**$**	**2,525,675**
P37676	Workplace Strategy & Design Fitness	**$**	**2,327,944**
P39029	Rooftop Solar - FP	**$**	**2,160,050**
P37047	Joint Pole Construction	**$**	**2,124,742**
P37217	Electric Avenue Improvements	**$**	**2,118,762**
P37593	Boeckman Road Widening	**$**	**2,088,975**
P36645	DPU Relay Replacement Program	**$**	**1,762,181**

P36617	South Milliken 57kV Line Rebuild	**$**	**1,699,525**
P37093	Facilities Management Fitness	**$**	**1,620,367**
P37427	Expeto Wireless Platform & Service	**$**	**1,587,958**
P37359	Integrated Dist Planning Tools	**$**	**1,500,000**
P36582	Substation FITNES 2019-2021	**$**	**1,422,528**
P36679	Orenco Substation 115kV Rebuild	**$**	**1,360,986**
P36723	Field Area Network Project (FAN)	**$**	**1,346,870**
P36417	Replace/Rewind Failed Transformers	**$**	**1,346,145**
P36285	PurchaseT&D - Tools & Lab Equipment	**$**	**1,250,000**
P37256	Amity Transformer Replacement	**$**	**1,048,051**
P35349	Dist Line Sys - Equip Replacement	**$**	**991,066**
P39037	Waconda Fiber Upgrades	**$**	**907,870**
P37521	Distribution State Est - ADMS	**$**	**835,584**
P39021	Farmington-River Road Round-A-Bout	**$**	**833,812**
P37450	Alternate AMI Solution	**$**	**832,951**
P39031	Print Mail Services Efficiency - FP	**$**	**816,416**
P16567	UG FITNES	**$**	**812,170**
P36859	ODOT Outer Powell Ph2-Road Improv.	**$**	**773,390**
P37020	Marquam Fiber Project	**$**	**766,974**
P37684	Mobile Programs	**$**	**765,689**
P36089	Transm Full Pole Inspct & Replace	**$**	**750,184**
P36235	Install Low OH Services Guarding	**$**	**706,485**
P39043	McLoughlin Sub V248 Brkr Replacemen	**$**	**684,126**
P37162	Bill Redesign	**$**	**658,667**
P36039	Harborton Reliability Project PH1	**$**	**619,370**
P37677	SOX and Usage Remediation	**$**	**611,824**
P37437	Woodburn New Site Project	**$**	**610,165**
P37167	Mitigate Overdutied Breaker Sherwd	**$**	**607,397**
P36550	Small Gen/QF/NM Interconnect Costs	**$**	**600,310**
P35556	Avian Protection Program	**$**	**547,415**
P37532	WTC to IOC Move	**$**	**523,700**
P39028	IQBD - FP	**$**	**458,126**
P14757	Underground Locating	**$**	**457,672**
P35149	Colstrip Transmission NW Energy	**$**	**457,168**
P37545	Municipal Charging Program	**$**	**445,300**
P35995	Downtown UG Core Cable Replacement	**$**	**396,785**
P37666	Urbint Project	**$**	**339,922**
P37685	Geotab Setup and Implementation	**$**	**330,273**
P37520	C2M Enhancements	**$**	**327,523**
P37232	Communications Fitness II	**$**	**298,614**
P37504	Smart Grid Chips Initial Deployment	**$**	**277,177**
P37168	2021-2022 QF Projects	**$**	**229,387**
P37594	PGE GIS QAQC Tool	**$**	**209,663**
P37526	Sec/Pri Network Power Flow - ADMS	**$**	**208,344**
P37382	ADMS CVR VVO	**$**	**176,650**
P36151	Eagle Take Permitting	**$**	**171,315**
P37528	Fault Protection Analysis	**$**	**168,071**

P39006	Customer Dashboard - FP	**$**	**160,000**
P36105	2016-2024 Dispatchable Standby Gen	**$**	**132,137**
P37822	Usage Request	**$**	**127,510**
P36725	Energy Storage - Baldock	**$**	**80,848**
P37331	CMD Network Protector Replacements	**$**	**30,399**
P36390	Redland Substation Upgrades	**$**	**28,579**
P36373	Blue Lake Phase II	**$**	**9,439**
P37669	Blue Lake Sub Interconnection	**$**	**9,439**
P17443	T&D Major System Inspect, Replace	**$**	**2,548**
P36649	Budget Only: Customer BSG Reserves	**$**	**603**
P37086	T&D BSG Reserve	**$**	**203**
P37791	SPQ0260 - Silver Creek Solar	**$**	**(263,500)**

PGE Exhibit 402 - Large Project Descriptions

Project #	Project Name	Strategy Alignment	Project Description	In Service Amounts
P36666	Build Evergreen Substation	Electrify	New substation build to meet customer's evolving electrification needs	$ 137,661,069
P37218	Overhead Distribution Inspections/Repairs	Perform	Inspection and repair of overhead services to ensure the highest level of customer safety and reliability	$ 128,561,087
P36954	Tonquin Substation Build	Perform	Increased customer reliability and operational flexibility by the addition of new distribution infrastructure	$ 41,889,684
P37302	Horizon-Keeler 230kV Transmission Line	Perform	Transmission expansion to enhance customer resiliency and energy market availability	$ 39,472,130
P36101	Substation Communication Upgrade	Perform	Improved tracking of system outages through communication equipment upgrades	$ 30,204,142
P36728	Coffee Creek - Energy Storage	Perform	Battery Technology to reduce duration of customer outages and improve power quality	$ 29,302,146
P14628	Replace Failed Underground Cables	Perform	Proactive replacement of aging cables to prevent customer outages or possible safety concerns	$ 25,262,098
P35890	Purchase Distribution Transformers	Perform	Customer growth driven electrical infrastructure need	$ 20,141,425
P35925	Distribution Customer Line Construction II	Perform	New and upgraded electric service work for residential and commercial customers	$ 19,463,178
P37214	Distribution Customer Line Construction III	Perform	New and upgraded electric service work for residential and commercial customers	$ 19,388,446
P37266	Reedville Substation Rebuild	Perform	Increase system resiliency at minimum cost by upgrading in existing substation footprint	$ 16,954,513
P36916	Harborton Reliabilty Ph2 - 115kV Transmission Line	Decarbonize	Transmission project to provide customer with better access to non-emitting energy sources	$ 16,540,811
P37048	Outage or Emergency Replacement Work	Perform	Customer service assets for emergency related repairs and replacements to lower duration of outages	$ 15,079,836
P37366	Shute Substation Upgrade	Electrify	Infrastructure build to meet the high power quality needs of large energy users	$ 14,898,016
P36953	Memorial Substation Build	Perform	Substation build to improve customer resiliency for critical infrastructure customer	$ 13,727,218
P37421	SCADA Upgrade at Jointly Owned Transmission Facility	Perform	Economically provide customers access to regional power by the use of jointly-owned and operated facilities	$ 13,203,400
P36770	Street & Area Lighting Construction	Electrify	Installation of customer focused, energy efficient lighting services	$ 11,917,095
P36422	Evergreen Property Land Purchase	Electrify	New substation build to meet customer's evolving electrification needs	$ 11,671,018
P35892	Purchase Customer Meters	Electrify	Advanced metering infrastructure to enable new customer programs and services	$ 11,538,208
P37213	Distribution System Construction III	Perform	General T&D construction costs in support of customer requests	$ 11,282,623

Exhibit 403 contains confidential information and is subject to

General Protective Order 23-132

Exhibit 404 - Level III Outage Accrual Mechanism Workpaper

2008 - 2023 Actual Level III Storm Damage Losses

CPI	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2008	$ 5,936,058															
2009	-0.32%	$ 2,106,514														
2010	1.64%	1.64%	$ -													
2011	3.14%	3.14%	3.14%	$ -												
2012	2.07%	2.07%	2.07%	2.07%	$ -											
2013	1.47%	1.47%	1.47%	1.47%	1.47%	$ -										
2014	1.62%	1.62%	1.62%	1.62%	1.62%	1.62%	$ 5,623,875									
2015	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	$ 5,161,601								
2016	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.28%	$ 4,504,081							
2017	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	$ 11,351,424						
2018	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%	$ -					
2019	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	$ 1,772,198				
2020	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	$ -			
2021	4.69%	4.69%	4.69%	4.69%	4.69%	4.69%	4.69%	4.69%	4.69%	4.69%	4.69%	4.69%	4.69%	$ 3,594,072		
2022	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	$ 20,171,812	
2023	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	$ -
2024	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%
2025	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%
2025$	$ 8,797,017	$ 3,131,808	$ -	$ -	$ -	$ -	$ 7,578,774	$ 6,948,445	$ 5,986,922	$ 14,773,667	$ -	$ 2,211,520	$ -	$ 4,231,471	$ 21,992,780	$ -

Ten Year Total Level III Storm Damage Losses	$ 63,723,578
Ten Year Avg Level III Storm Damage Losses	$ 6,372,358
Average Level III Storm Damage Losses	$ 9,103,368

Exhibit 404 - Level III Outage Accrual Mechanism Workpaper

Year	Level III Storm Actuals	CPI	
2008	$ 5,936,058	3.81%	
2009	$ 2,106,514	-0.32%	
2010	$ -	1.64%	
2011	$ -	3.14%	
2012	$ -	2.07%	
2013	$ -	1.47%	
2014	$ 5,623,875	1.62%	
2015	$ 5,161,601	0.12%	
2016	$ 4,504,081	1.26%	
2017	$ 11,351,424	2.13%	
2018	$ -	2.44%	
2019	$ 1,772,198	1.81%	
2020	$ -	1.25%	
2021	$ 3,594,072	4.69%	
2022	$ 20,171,812	7.99%	
2023	$ -	4.14%	
2024	$ -	2.66%	
2025		1.98%	November 2023 CPI

	Collection	Withdrawals	Balance
2011	$ 2,000,000	$ -	$ 2,000,000
2012	$ 2,000,000	$ -	$ 4,000,000
2013	$ 2,000,000	$ -	$ 6,000,000
2014	$ 2,000,000	$ 5,623,875	$ 2,376,125
2015	$ 2,000,000	$ 5,161,601	$ -
2016	$ 2,000,000	$ 4,504,081	$ -
2017	$ 2,000,000	$ 11,351,424	$ -
2018	$ 2,600,000	$ -	$ 2,600,000
2019	$ 3,804,696	$ 1,772,198	$ 4,632,498
2020	$ 3,804,696	$ -	$ 8,437,194
2021	$ 3,804,696	$ 3,594,072	$ 8,647,818
2022	$ 3,618,465	$ 20,171,812	$ (7,050,700)
2023	$ 3,525,350	$ -	$ (3,525,350)
2024			

Exhibit 405 - UE 435 IRM Project List

No.	Project Description	$ 442,002,135 2025	$ 479,101,068 2026	$ 581,570,929 2027	$ 538,683,459 2028
P14628	Replace Failed Underground Cables	16,500,000	18,150,000	19,965,000	22,000,000
P14757	Underground Locating	270,530	278,645	287,005	295,615
P16567	UG FITNES	450,000	450,000	450,000	450,000
P35149	Colstrip Transmission NW Energy	572,589	572,589	572,589	
P35349	Dist Line Sys - Equip Replacement	600,000	600,000	600,000	
P35484	Repl Trans Structures & Insulators	2,000,000	2,000,000	2,000,000	2,000,000
P35556	Avian Protection Program	350,000	350,000	350,000	350,000
P35846	CPP Switch Replacement	508,220	559,000	615,000	676,000
P35890	Purchase Distribution Transformers	23,678,978	26,100,000	26,900,000	27,500,000
P35892	Purchase Customer Meters	9,950,000	10,250,000	10,560,000	10,880,000
P35908	SAM: Proactive UG Cable Program	5,900,000	5,900,000	5,900,000	5,900,000
P35980	PCB Transformer Replacement		3,300,000	5,400,000	5,400,000
P35995	Downtown UG Core Cable Replacement	2,500,000	-	-	
P36089	Transm Full Pole Inspct & Replace	1,000,000	-	-	-
P36151	Eagle Take Permitting (Biglow-Pelton)	500,000	500,000		
P36170	OHSU Infrastructure Upgrades	100,000	100,000	100,000	100,000
P36235	Install Low OH Services Guarding	503,027	438,601	464,926	475,098
P36285	PurchaseT&D - Tools & Lab Equipment	1,250,000	1,335,000	1,475,000	1,500,000
P36417	Replace/Rewind Failed Transformers	2,350,000	2,350,000	-	-
P36537	Unjacketed Cable Replacement Prgrm	23,100,000	25,000,000	38,500,000	53,200,000
P36564	Harrison (Stephens 11kV Conversion) Project	5,260,645			
P36617	South Milliken Line Rebuild	16,000,000	15,000,000	20,000,000	15,000,000
P36641	Oil Spill Containment Modifications	350,000	350,000	350,000	350,000
P36645	DPU Relay Replacement Program	700,000	700,000	700,000	700,000
P36913	Trans. Line Clearance Mitigation	3,000,000	3,000,000	3,000,000	-
P37046	T&D Asset Relocation	15,700,000	15,700,000	15,700,000	15,700,000
P37047	Joint Pole Construction	900,708	918,722	937,097	955,839
P37048	Outage or Emergency Replacement	6,100,000	6,200,000	6,300,000	6,400,000
P37049	Line Crew Truck Stock Materials	3,400,000	3,400,000	3,400,000	3,400,000
P37061	OH FITNES Transmission	6,000,000	4,500,000	4,500,000	4,500,000

P37211	Substation Cap Rplcmts 2022-2024	3,850,000	4,235,000	4,658,500	5,124,350
P37213	Distribution System Construction III	15,800,000	16,300,000	16,800,000	
P37218	OH FITNES Distribution	80,800,000	68,300,000	60,400,000	52,100,000
P37232	Communications Fitness II	500,000	600,000	800,000	800,000
P37242	WF - Tree Attachments	3,090,000	2,000,000	1,000,000	
P37266	Reedville Substation Rebuild	2,159,138	3,453,974	4,000,000	
P37331	CMD Network Protector Replacments	330,000	150,000		
P37352	Customer Reliability Improvement	505,000	3,900,000	2,050,000	1,050,000
P37421	Foreign Utility Blanket	3,000,000	3,000,000	3,000,000	3,000,000
P37494	Replace Livefront Padswitches with Deadfront	2,650,000	4,020,000	4,225,000	4,434,000
P37512	WF-UG Scoggins-Cherry Grove Feeder	6,945,085			
P37514	WF-UG Grand Ronde-Agency Feeder	15,855,143	2,197,341		
P37516	WF - Expulsion Fuse Replacement	2,625,000			
P37518	Leland-Carus Reconductor (WF)	16,682,114	16,076,965	5,390,036	
P37663	WF Distribution Pole Replacement Program - UAM	3,150,000	3,307,500	3,472,875	3,646,519
PXXX03	Canyon to Marquam 13kV Network Feeder Ties	500,000	2,000,000	5,000,000	
PXXX09	Canyon Substation Rebuild			1,001,908	26,121,183
PXXX13	Sylvan - Substation Rebuild	2,939,907	9,941,417	8,000,000	2,000,000
PXXX20	Kaster (Cascade II) New Substation Build	9,146,336	10,000,000	3,783,827	
PXXX34	Glencullen Substation Rebuild	15,000,000	10,000,000	6,000,000	
PXXX35	Cedar Hills Breakers	710,034	787,403	504,311	
PXXX44	Proactive Transformer Replacement	800,000	2,200,000	3,393,428	2,998,410
P39010	WF - UG Willamina-Buell Feeder	20,000,000	20,000,000	20,000,000	20,000,000
P37703	WF Early Fault Detection (EFD)	630,000	630,000	630,000	630,000
PXXX86	Oil Circuit Breaker Replacement Program	1,725,000	3,000,000	4,000,000	6,000,000
PXXXXX	Proactive Aging Asset Substation Replacement Investment	52,651,975	110,366,589	116,648,161	120,720,179
PXXXXX	Eagle Creek Substation Rebuild	6,968,974	1,718,377		
PXXXXX	Substation Storage	4,058,161			
PXXXXX	Arc Flash Program	3,508,652	6,316,266	6,316,266	6,316,266
PXXXXX	Rivergate South-11011 Reconductor	400,000			
PXXXXX	Six Corners-13 Reconductor	957,150	360,368		
PXXX84	Breaker Failure Protection for Oil Breakers	250,000			
PXXXXX	DER Substation Improvements	1,172,768	777,311		
PXXXXX	WF-UG Summit-13	828,000	8,280,000	8,280,000	

PXXXXX	WF-UG Summit-Meadows	528,000	5,280,000	5,280,000	
PXXXXX	WF-UG+TW Orient-Oxbow	1,190,000	11,900,000	11,900,000	
PXXXXX	WF-UG Welches-Zig Zag	4,476,000		44,760,000	44,760,000
PXXXXX	WF-UG+TW Estacada-North Fork	6,125,000		61,250,000	61,250,000

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Production

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Benjamin Felton

February 29, 2024

Table of Contents

I. Introduction

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

A. My name is Benjamin Felton. I am employed by Portland General Electric Company (PGE) as the Executive Vice President and Chief Operating Officer. My qualifications appear at the end of PGE Exhibit 400.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the operation and maintenance (O&M) expenses associated with PGE's long-term power supply resources, propose updates to our major maintenance accruals (MMA), and support the investments PGE is making in two major battery energy storage system (BESS) projects. My testimony also supports use of the renewable automatic adjustment clause (RAAC) for associated stand-alone battery storage.

Q. How is the remainder of your testimony organized?

A. After this introduction, our testimony has six additional sections:

- Section II – Summary;
- Section III – Generation Resources and Plant Performance;
- Section IV – 2025 Test Year Generation O&M Expenses;
- Section V – Major Maintenance Accruals;
- Section VI – Battery Energy Storage System Projects; and
- Section VII – Associated Storage.

II. Overview and Summary

Q. Please summarize your request for this filing.

A. We request that the Commission approve our 2025 forecast of $129.5 million in generation O&M costs, excluding IT-related expenses, which are discussed in PGE Exhibit 300. The 2025 forecast represents an $8.1 million increase from the 2024 budget due primarily to non-labor costs escalation and increased maintenance costs. Additionally, we request that the Commission approve recovery of the costs associated with two major BESS projects and agree to PGE's proposed treatment of the associated investment tax credits (ITCs). Finally, we request that the Commission recognize as eligible for recovery under Schedule 122, the Renewable Automatic Adjustment Clause (RAAC), standalone energy storage connected at the transmission-voltage level as associated energy storage.

Q. How would approval of PGE's request benefit customers?

A. Customers count on PGE to power their lives and businesses. Approval of PGE's request allows for the vital work needed to reliably serve all customers. Through the Distribution Standby Generation program, customer-owned backup generators can provide the required reserves. Work on major maintenance ensures the generation resources serving customers today can continue to operate and serve customers into the future. PGE's battery energy storage projects will help strengthen the energy grid, by serving customers with improved reliability during the transition to more renewable resources. PGE's ITC proposal provides direct benefits for customers, offsetting the costs of the battery storage projects.

III. PGE's Generation Resources

A. Generation Resources

Q. Have you prepared an exhibit identifying all of PGE's power supply resources for the 2025 test year?

A. Yes. Confidential PGE Exhibit 501 lists PGE's generating resources and expected average energy output as modeled under normal conditions for PGE's initial 2025 Net Variable Power Cost (NVPC) forecast.

Q. Is PGE adding any generation resources to its portfolio in 2024 or 2025 that aim to increase reliability while reducing emissions?

A. Yes. Pursuant to PGE's 2019 Integrated Resource Planning (IRP), the Commission-acknowledged 2019 IRP Action Plan, and subsequent request for proposals (2021 RFP Docket No. UM 2166), PGE recently added a renewable resource, the Clearwater Wind Project (Clearwater),[1] and will be adding non-emitting dispatchable capacity resources, Troutdale, Constable, and Seaside battery storage facilities, at the end of 2024 and mid-2025. Constable and Seaside are discussed further in Section VI.

Q. Is PGE currently performing any new major upgrades to generation resources that it can call on in times of critical need?

A. Yes. We are completing the Diesel Particulate Filters (DPF) Installation Program in 2024.

Q. Please briefly describe the Diesel Particulate Filters Installation Program.

A. PGE has a Distributed Standby Generation (DSG) program under which the Company can start, operate, and monitor customer-owned backup generators when needed to provide North American Electric Reliability Corporation (NERC)-required operating reserves. This host of

[1] Clearwater was placed into service in January 2024. *See* Docket No. UE 427 for further detail on Clearwater.

customer-owned generators provides multiple grid services, including Contingency Reserve and Frequency Reserve, and gives PGE the ability to distribute and aggregate these cost-effective energy resources to support system reliability. In 2022, the Oregon Department of Environmental Quality (DEQ) revised the specifications of the General Air Containment Discharge Permit (ACDP)[2] for DSG units to require the installation of DPFs on customer-owned diesel-fueled electrical power generators. Therefore, to maintain compliance for participating generators and retain the generators in the crucial DSG program, PGE must install DPFs on 56 generators totaling 73.8 MWs. Failure to install DPFs by September 28, 2024, would result in non-compliance and limit compliant DSG units available for service. The expected amount to close to plant in 2024 is $37.5 million.

Q. Please elaborate on the value that PGE's DSG program provides to PGE customers.

A. As mentioned, PGE's DSG program provides the following grid services:

- Contingency Reserve: PGE's DSG program provides Contingency Reserves required by NERC Reliability Standards. When a dispatch event is called, the Contingency Reserve portfolio typically delivers 90% of capacity within two minutes and 100% of capacity within five minutes. On average, the Contingency Reserve portfolio is called upon five to ten times per year to serve PGE's Contingency Reserve Obligation (CRO).
- Frequency Response and Spinning Reserves: PGE's DSG program actively dispatches resources that respond promptly, typically within 4.5 seconds. This rapid response is crucial in meeting the Frequency Response Obligation and Spinning

[2] Permit Number: AQGP-018a.

Reserve requirements mandated by NERC Reliability Standards,[3] contributing to the stability of the grid.

- Local Distribution Support: The DSG program plays a vital role in emergency distribution congestion relief by supplying power to counteract overloading on distribution infrastructure. This capability enhances the resilience and efficiency of the local distribution network.

Q. Is PGE forecasting any additional changes to its DSG program?

A. Yes. In addition to the above capital project associated with existing DSG facilities, PGE is expanding its DSG program in 2024 by adding 60 MW of incremental DSG capacity. The addition of 60 MW to PGE's existing program capacity of approximately 115 MW is a cost-effective means of helping to meet PGE's CRO of approximately 225 MW. Prior to 2021, 50% of CRO was required to be met with spinning reserves. This requirement has since been changed such that 100% of CRO can be met using non-spinning reserves. Because of this change, PGE's DSG program, which is a cost-effective and valuable capacity resource, can now cover a greater share of PGE's CRO for the benefit of PGE's customers.

Q. What is the forecasted cost of acquiring these incremental DSG resources?

A. PGE has included approximately $20 million in rate base within its deferred programs and investments and approximately $2.2 million in O&M expense to reflect an amortization life of ten years on an investment of approximately $22.2 million in total.

[3] Reliability Standard BAL-003-2.

B. Plant Performance

Q. How did PGE's gas plants perform in 2023?

A. In 2023, PGE's gas plants continued to perform well. Overall, the gas generation fleet maintained an average capacity Weighted Equivalent Availability Factor (WEAF) of 85.9% in 2022 and 86.1% in 2023.[4]

Confidential PGE Exhibit 502 provides historical 2021 through 2023 gas plant availability.

Q. How does the 2025 expected generation for PGE's gas plant resources compare to previous years?

A. Confidential PGE Exhibit 503 provides actual gas plant generation for 2021, 2022, 2023, along with a 2025 forecast for each of our gas resources. PGE's 2025 AUT filing provides PGE's 2025 initial NVPC forecast and supporting documentation regarding the MONET forecasted economic dispatch of PGE's gas plants.

[4] WEAF, as defined by NERC, is the percent of time available without outages, derates or seasonal derates.

IV. Generation Plant O&M

A. Generation Plant O&M Expenses

Q. What is your 2025 test year forecast of generation O&M expenses?

A. Our test year forecast of generation O&M expenses is approximately $129.5 million excluding Information Technology (IT) costs. This represents an $8.1 million increase over the 2024 budget. Table 1 below summarizes these costs.

Table 1
Generation Plant O&M Summary ($ millions)**

O&M Expenses	2023 Actuals	2024 Budget	2025 Test Year	'24-'25 Delta	Annual % Change
Labor	$41.8	$38.9	$43.4	$4.5	11.4%
Non-Labor	$46.0	$53.9	$56.7	$2.8	5.1%
Major Maintenance Accrual	$18.9	$20.9	$21.7	$0.8	3.7%
Plant Subtotal*	**$106.6**	**$113.7**	**$121.7**	**$8.0**	**7.0%**
Environmental Services	$6.5	$7.6	$7.7	$0.1	1.2%
Subtotal*	**$113.2**	**$121.4**	**$129.5**	**$8.1**	**6.7%**
Information Technology (IT)	$14.6	$18.1	$20.0	$1.9	10.8%
Total*	**$127.8**	**$139.5**	**$149.5**	**$10.0**	**7.2%**

** May not sum due to rounding*
***Please note that both actuals and forecast costs for Boardman & Colstrip are excluded for comparison purposes. No Boardman costs exist in the 2025 test year, aside from Schedule 145 decommissioning costs.*

Q. Why are you comparing the 2025 test year costs to the 2024 budget?

A. We do this comparison because the 2024 budget approximates final costs in PGE's retail rates, as approved by Commission Order No. 23-476 in Docket No. UE 416 (UE 416). As noted in PGE Exhibit 200, because we are holding PGE's overall 2024 O&M budget nearly flat to the final stipulated costs from UE 416, comparing the 2025 forecast to the 2024 budget provides a reasonable reflection of the anticipated requested incremental cost increase.

Q. How are labor and non-labor generation O&M expected to change from the 2024 budget to the 2025 forecast?

A. We project labor-related generation O&M to slightly increase in 2025, as shown in Table 1 above. PGE's overall labor is discussed in PGE Exhibit 300, and we discuss labor-related plant generation O&M in Section IV.B.2, below. We project non-labor-related plant generation O&M, with IT expenses excluded, to increase by approximately $3.5 million in 2025. This figure can be found below in Table 2.

Q. What do IT costs represent in Table 1?

A. Table 1 shows IT costs that are directly assigned or allocated to generation. These IT costs support PGE's efforts to develop, operate, and maintain our computer, information, cyber security, and communication systems. Because IT costs are charged or allocated to all operating areas of the company, they are discussed in detail in PGE Exhibit 300.

B. Generation O&M Major Drivers

1. Non-Labor O&M Expenses

Q. What is the change in generation non-labor plant O&M expenses from 2024 to 2025?

A. The changes in non-labor plant O&M expenses from 2024 to 2025 are summarized in Table 2 below.

Table 2
Generation Non-Labor O&M Changes ($ millions)**

Operating Area	2023 Actuals	2024 Budget	2025 Test Year	'24-'25 Delta	Annual % Change
Gas-Fired Plants	$17.6	$19.2	$19.4	$0.2	0.9%
Hydro Plants	$4.4	$5.7	$6.0	$0.3	5.7%
Wind Plants	$17.1	$20.8	$23.6	$2.8	13.5%
Major Maintenance Accrual	$18.6	$20.9	$21.7	$0.8	3.7%
General and Miscellaneous	$6.9	$8.1	$7.6	($0.6)	-6.8%
Subtotal*	**$46.0**	**$53.9**	**$56.7**	**$2.8**	**5.1%**
Major Maintenance Accrual	$18.6	$20.9	$21.7	$0.8	3.7%
Environmental	$3.5	$4.3	$4.3	($0.0)	-0.7%
IT Expenses	$10.2	$12.1	$13.0	$1.0	7.9%
Total*	**$78.2**	**$91.2**	**$95.7**	**$4.5**	**4.9%**

**May not sum due to rounding.*
***Please note that historical costs for Boardman & Colstrip are excluded for comparison purposes.*

Q. What is driving the changes in non-labor plant generation O&M expenses between 2024 budget and 2025 forecast?

A. The primary driver for the change in non-labor O&M expenses is the appearance of an increase to costs associated with Clearwater. Specifically, PGE is obligated to pay $6 million in Custer County impact fees ($2 million annually) from 2024 to 2026.[5] However, because the 2024 fee of $2 million was capitalized while the subsequent annual $2 million fee is defined as an O&M expense, the 2025 test year O&M forecast for Clearwater appears $2 million greater than 2024 budgeted amounts. This reclassification of the Custer County impact fee accounts for the majority of the $2.8 million increase in wind generation expenses.

2. Labor O&M Expenses

Q. Is generation labor O&M forecast to increase from 2024 to 2025?

A. Yes. If excluding IT and environmental services expenses, generation labor O&M expenses are forecast to increase by approximately $4.5 million (or 11.4%) in 2025 compared to the 2024 budget, as shown in Table 3 below. There are three reasons for this increase. First, approximately $2.1 million of the variance is from the appearance of an increase resulting from an allocation shift in PGE's unfilled position adjustment. As discussed in PGE Exhibit 300, Section IV, PGE has included a downward adjustment of approximately $11.7 million to account for vacancies and/or unfilled positions. A similar-sized adjustment (approximately $11.8 million) was also incorporated into PGE's 2024 budget. However, the distribution of these dollars between major operating areas shifted between 2024 and 2025, which resulted in production O&M receiving approximately $3.2 million of the total

[5] Custer County is authorized to receive impact fees from owners or operators of wind generation facilities used for a commercial purpose.

adjustment in 2025 versus $5.3 million in 2024. Thus, what appears to be a cost increase is not actually an increase but is a result of a shift in year-over-year accounting geography.

Second, base labor escalation consistent with the escalation factors referenced in PGE Exhibits 200 and 300 accounts for approximately $1.8 million of the 2025 labor increase. Finally, the remaining increase of approximately $0.6 million is due to the addition of six positions. Two positions to our Renewable Operations department to support increased renewables growth, and four positions to our Customer Specialized Programs department to provide 24/7 support for PGE's distributed energy resource management system (DERMS) operation desk.

Table 3
Generation Labor O&M Changes ($ millions)**

Operating Area	2023 Actuals	2024 Budget	2025 Test Year	'24-'25 Delta	Annual % Change
Gas-Fired Plants	$17.8	$17.2	$18.0	$0.8	4.9%
Hydro Plants	$7.4	$7.6	$7.9	$0.4	4.8%
Wind Plants	$1.5	$1.5	1.6	$0.1	3.7%
General and Miscellaneous	$15.0	$12.7	$15.9	$3.2	25.2%
Subtotal*	**$41.8**	**$38.9**	**$43.4**	**$4.5**	**11.4%**
Environmental	$3.1	$3.3	$3.4	$0.1	3.8%
IT Expenses	$4.4	$6.0	$7.0	$1.0	16.5%
Total*	**$49.2**	**$48.2**	**$53.8**	**$5.6**	**11.6%**

**May not sum due to rounding.*
***Please note that historical costs for Boardman & Colstrip are excluded for comparison purposes.*

V. Major Maintenance Accrual

Q. Please explain the Major Maintenance Accrual (MMA) mechanism.

A. Major maintenance costs can vary dramatically from year to year, and absent an MMA, PGE would expense the major maintenance costs in the period the work is performed. Accounting for costs in this manner has two significant drawbacks: 1) it does not allow the recording of expense in the same period the benefits occur; and 2) it results in an expense that is cyclical and "lumpy" over several years that can have material swings to customer prices. To remedy these drawbacks, Commission Order No. 95-1216 (Docket No. UE 93) approved an accrual and balancing account treatment for major maintenance costs through the use of the MMA mechanism.

The MMA is based on a multi-year forecast of major maintenance activities with an accrual estimate designed to bring the balancing account to zero at the end of the multi-year period. By balancing the costs and collections, PGE achieves an appropriate matching of costs to both the period and customers benefited. The accrual also results in a better matching of costs with revenue, without requiring PGE to file a rate case every year to capture changes in major maintenance costs.

Q. What assets are currently included in the MMA mechanism?

A. PGE currently has MMAs for Port Westward 1 & 2, Coyote Springs, Carty, Colstrip, and KB Pipeline. However, the Colstrip MMA cost is not included in this case as PGE recovers these costs through Schedule 146. Major maintenance events occur based upon 1) maintenance intervals that are generally dependent upon a facility's capacity factor (hours run/hours in period) or established under PGE's long-term service agreements (LTSAs);[6] or 2) based upon time intervals, such as every four years as is the case with Colstrip. Listed below are examples of major maintenance items:

- Major Turbine and Generator Inspections to perform advanced assessments, along with related work that may include combustion turbine alignment; exhaust frame modifications; and repairs to thrust bearings, the generator stator, and the generator field.
- Hot Gas Path Inspection including the disassembly of combustion and turbine sections of the combustion turbine so that parts may be inspected, and repaired or replaced, as necessary. The combustion section is where the natural gas is combined with compressed air and burned. The turbine section is where mechanical energy is extracted from the high-speed flow of hot combustion gases exiting the combustion chambers.
- Selective catalytic reduction catalyst replacements.
- Auxiliary boiler maintenance.
- High-pressure boiler clean.
- High-pressure turbine chemical clean.
- Kelso-Beaver pipeline regulatory-related activities.

Q. How does PGE calculate the MMA for its gas plants?

A. PGE calculates the MMA for its gas plants by forecasting the expected operational run of each gas plant over a five-year period using the MONET model and based on hours of plant

[6] LTSAs require that the original equipment manufacturer provide maintenance services for their equipment pursuant to the terms and conditions of the agreement.

operation, forecasting the timing for major maintenance activities. PGE then averages the total estimated maintenance costs over that five-year period to obtain an annual major maintenance expense.

Q. What is the total MMA amount included in the 2025 test year plant O&M costs?

A. The total MMA amount included in the 2025 test year is approximately $16.7 million, inclusive of amounts recorded under Account 456, Other Revenues.[7] As noted previously in Table 1, the 2025 test year MMA expense charged to generation O&M is forecasted to increase by approximately $0.8 million over 2024 budgeted major maintenance expenses. However, as reflected in PGE Exhibit 504, 2025 forecasted MMA expense, inclusive of MMA amounts recorded in Account 456, Other Revenues, is approximately $0.6 million higher than the UE 416 annualized MMA collection amount currently in base rates.[8]

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[7] Amounts recorded under Account 456, Other Revenues represent levelized MMA revenues that result from the amortization of the MMA collections.

[8] *See* Exhibit 504, cell H7.

VI. Battery Energy Storage System Projects

A. IRP and RFP Processes

1. IRP Process and Identification of Capacity Need

Q. Did PGE identify a need for capacity resources in its 2019 IRP?

A. Yes. PGE's 2019 IRP and IRP Update forecast a capacity shortfall beginning in 2025.[9] Through a robust analysis, PGE's 2019 IRP Action Plan identified a capacity need of 511 MW[10] in 2025 and provided that PGE would conduct an all-source RFP to seek approximately 150 MWa[11] of renewable resources and non-emitting dispatchable resources (i.e., clean capacity) to meet the remainder of PGE's 388 MW capacity need, which was reduced due to PGE's renewal of a long-term hydroelectric power purchase agreement (PPA), by the end of 2024.

Q. Is the acquisition of the BESS projects consistent with the Commission-acknowledged 2019 IRP Renewable Action Plan?[12]

A. Yes. Upon completion, the BESS projects will collectively provide approximately 262 MW of capacity contribution for both PGE and our customers given their 475 MW of non-emitting dispatchable nameplate capacity.[13] Further details on the Constable (formerly Evergreen) and

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[9] Docket No. LC 73, Order No. 20-152 (May 6, 2020) and Order No. 21-129 (May 3, 2021).

[10] This 2025 capacity need decreased from 511 MW to 372 MW after PGE renewed a long-term hydroelectric PPA with the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS) for their share of the Pelton Round Butte (PRB) output (Docket No. UM 2176). The renewed PPA will be effective from 2025 through 2040. Additionally, after incorporating the March 2022 load forecast, the 2025 capacity need slightly increased to 388 MW (for further detail *see* Docket No. UM 2166, "PGE's Final Shortlist and IE's Closing Report" (May 5, 2022).

[11] We note that UM 2166's Order No. 22-315 at 6 (Aug 31, 2022) acknowledged PGE's final shortlist and included a condition that the most "reasonable course of action" would be to target an acquisition level of 250 MWa.

[12] The Commission acknowledged PGE's 2019 IRP Renewable Action Plan in Order No. 20-152 on May 6, 2020. Following this, PGE filed a 2019 IRP Update, which contained no changes to the Renewable Action Plan, that was acknowledged in Order No. 21-129 on May 3, 2021.

[13] 44 MW for Constable, 111 MW for Seaside, and 124 MW for Troutdale, the latter from which PGE will purchase capacity under a 20-year storage capacity agreement.

Seaside BESS projects are discussed in subsections B and C below, and information on the Troutdale BESS is available in PGE's 2025 AUT filing.

2. Request for Proposals Process and Selection of Resources

Q. When did PGE issue its 2021 RFP?

A. We began our RFP process in April 2021 (Docket No. UM 2166). After a robust process with OPUC Staff and intervenors, and Commission approval,[14] PGE issued its final RFP to the market in December 2021.

Q. Was an Independent Evaluator (IE) selected to oversee the RFP?

A. Yes. Per Competitive Bidding Rules,[15] Bates White was selected to serve as the IE for the RFP. The IE reported directly to the Commission and its work was directed by OPUC Staff. The IE participated in the entire RFP process from design, through bid receipt and analysis, to the selection of the shortlist, continuing through final negotiations with all selected counterparties. As part of this engagement, the IE: 1) monitored bidder contact, including the answers to bidder questions; 2) provided input with respect to bidder disqualifications; 3) reviewed all price and non-price scores and models for PGE's shortlist process; 4) independently scored all bids; 5) submitted closing reports to the Commission after PGE identified the final shortlist; and 6) reviewed and verified PGE's price update following the acknowledgement of PGE's final shortlist.

Q. Did PGE propose a Scoring and Modeling Methodology consistent with OAR 860-089-0250?

A. Yes. Prior to the submission of PGE's draft RFP and in conjunction with filing to request approval of an IE, PGE included a proposed scoring and modeling methodology, consistent

[14] *See* UM 2166, Order No. 21-460 (Dec 10, 2021).
[15] *See* OAR 860-089-0200.

with OAR 860-089-0250(a). Ultimately, PGE's scoring and modeling methodology for the 2021 RFP was adopted, with certain Staff recommended conditions, through Commission Order No. 21-320.

Q. Did the RFP design have any other changes following the adoption of a scoring and modeling methodology?

A. Yes. Subsequent to the adoption of a scoring and modeling methodology and as part of the approval of PGE's RFP, the Commission ordered additional modifications to the RFP design, which PGE incorporated into the final RFP issued to market participants.

Q. How did PGE evaluate the dispatchable resource bids?

A. PGE evaluated the dispatchable resource bids based on a combination of price and non-price points, with 81.2% of available bid points based on the price and performance considerations reflected in the price score and 18.8% of the available bid points based on non-price factors that could not be readily converted into minimum bidder requirements. PGE also followed specific scoring criteria and methodology for dispatchable resource bids as specified in the Commission-approved final 2021 RFP.

Q. How did PGE determine the price scores?

A. PGE prepared financial models for all submitted bids. These models calculated a lifecycle economic value for each bid. The final price score was based on the ratio of the bid's (1) total real levelized costs to (2) the real levelized benefits of expected energy value, capacity value, and flexibility value over the same term, and was consistent with analysis performed in PGE's acknowledged 2019 IRP and IRP Update and consistent with the scoring methodology adopted through Commission Order No. 21-320 and approval of PGE's RFP through Commission Order No. 21-460.

Q. How did PGE determine the non-price scores?

A. Certain project-specific risks and benefits cannot be captured or quantified by evaluating a bid's price or resource portfolio cost benefit. For these risks and benefits, PGE evaluated and assigned a non-price score for dispatchable resources based on considerations of commercial performance risk and commercial operation date-related risks pursuant to the matrix and scoring criteria published and approved in the final RFP.

Q. How many bids were received in response to PGE's offering?

A. PGE received bids from 19 counterparties, who together offered 110 distinct proposals, including 15 benchmark proposals. The process, designed in conformance with the Competitive Bidding Rules,[16] required the benchmark bids to be received and evaluated prior to PGE's receipt of all other bids. Following the receipt and scoring of all offers, PGE identified an initial shortlist containing 44 bids that included diverse commercial structures and resource technologies representing 1,915 MWa of total energy generation, with 1,325 MWa of non-benchmark resources. PGE identified the initial shortlist after performing individual bid analysis and assigning both price and non-price scores.

Q. How was the final shortlist developed?

A. In addition to the combination of price and non-price scores used to determine the initial shortlist, PGE requested and received best and final offers, performed additional due diligence to confirm conformance with the 2021 RFP requirements, and updated scores to identify PGE's final shortlist. Finally, PGE performed a portfolio analysis to inform the development of the final shortlist. This analysis, in addition to the price and non-price scores, allowed PGE

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[16] *See* OAR 860-089-0350.

to create a final shortlist that identified the non-emitting capacity resources representing the least-cost and least-risk options for our customers and the company.

Q. How many bids made the final shortlist?

A. From the initial shortlist of 44 bids, 29 were placed on PGE's final shortlist, which represented 13 unique projects. Of that total, PGE's final dispatchable generation shortlist included a total of six dispatchable generation projects with 11 total project variations, representing enough projects to provide 497 unique MW of dispatchable capacity.[17]

Q. Did the IE file a final shortlist report?

A. Yes. The IE concluded in its final shortlist report filed on May 5, 2022 that the RFP process was run in accordance with the rules and that the process was reasonably competitive.[18] Specific to the benchmark bids submitted in the process, the IE undertook a multi-part review of the offers, ultimately concluding that the benchmark bids were acceptable.[19] The IE also stated portfolio modeling suggested a clear preference for bids consistent with PGE's shortlist scoring.[20] Finally, the IE confirmed the selected bids were all reasonably priced, were selected fairly in accordance with the approved RFP scoring system, and that the RFP aligned with PGE's IRP process.[21]

Q. Were there any price scoring updates after the Commission's final shortlist acknowledgement on July 14, 2022, and if so, what were the results?[22]

A. Yes. Due to unusual events, including global supply chain disruptions, significant inflation levels, and the passage of the Inflation Reduction Act (IRA), PGE offered all final shortlisted

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[17] UM 2166, PGE's Final Shortlist Request for Acknowledgement (May 25, 2022) at 18.
[18] UM 2166, Bates White Final Closing Report (May 5, 2022) at 1.
[19] *Id.* at 8.
[20] *Id.* at 2.
[21] *Id*. at 1-2.
[22] UM 2166*,* Order No. 22-315 (Aug 31, 2022).

bidders an additional opportunity to modify the price and/or commercial operation date (COD) terms of their bids. Bidders were allowed to adjust their prices higher or lower and update their COD within the limits set by the previously established RFP COD constraints. These updates were submitted by bidders on August 26, 2022, which resulted in refreshed price scoring and portfolio modeling analysis.

Q. What were the top-performing dispatchable generation bids?

A. The top-performing dispatchable bids included three projects: Troutdale, Constable, and Seaside. All top-performing bids were four-hour batteries offered at several sizes under various transaction types.

Q. How much capacity will the three BESS projects provide?

A. The RFP sought a total target of 375 MW of capacity resources. The three BESS projects will collectively provide approximately 262 MW of capacity contribution or 475 MW of non-emitting dispatchable nameplate capacity.[23]

Q. Did the IE review PGE's refreshed price scoring and portfolio modeling analysis?

A. Yes. PGE consulted with the IE through this process and provided the IE with updated price scores and rankings for the remaining shortlisted bids. After examining all the information provided, the IE concluded that PGE had appropriately modeled and updated prices for all offers using the methods and models in the RFP.

Q. Does Seaside's final design and expected timing differ from the RFP bid proposal?

A. Yes. After the conclusion of the RFP the Seaside bidder presented an update to PGE that modified the project's capacity and COD. The bidder had successfully acquired adjacent real-estate that would accommodate 200 MW of battery energy storage in alignment with the

[23] Clearwater will provide approximately 108 MW of capacity, leaving a target of 267 MW before consideration of the three BESS projects.

bidder's maximum capacity under their interconnection agreement. The bidder identified the need to extend the project COD by approximately six months to update permits associated with the new parcel. The bidder informed PGE that it would not continue commercial negotiations for the project as bid and would only continue commercial negotiations for the project at the adjacent project site with a COD extension.

Q. Why did PGE accept the bidder's Seaside update?

A. Seaside was deemed acceptable for several reasons. PGE identified that its capacity needs justified procuring the larger Seaside project. Additionally, the price of the project on a per kW basis aligned with the RFP bid price despite the 75 MW increase in nameplate capacity. The updated cost proved more favorable than dispatchable capacity alternatives on the final shortlist, making the bidder update the most cost-effective and beneficial outcome for customers for meeting PGE's near-term capacity needs. Lastly, choosing to not procure the Seaside project in the 2021 RFP and instead consider procuring Seaside in a future solicitation would endanger PGE's ability to meet its capacity needs in 2025 and 2026.

Q. Did the IE consider PGE's decision regarding Seaside to be reasonable?

A. Yes. The IE found PGE's decision regarding Seaside to be reasonable for several reasons. First, the price was already vetted in the RFP, and the offer's terms and conditions remained largely consistent with the original bid. Second, even considering the Troutdale and Constable bids, PGE's capacity needs persisted, making the larger purchase justifiable. Third, the delay would be relatively short, amounting to a six-month extension.

B. Constable BESS Project

1. Constable Technology

Q. Please describe the Constable BESS project (Constable).

A. Constable is a lithium-ion BESS with 75 MW nameplate capacity and four-hour storage capability (i.e., 300 MWh discharge over four hours) that will be located in Hillsboro, Oregon. Constable has an expected in-service date on or around December 31, 2024, and upon completion will interconnect to the newly constructed Evergreen Substation (Evergreen) that has an expected in-service date of June 30, 2024. PGE is the current owner of the interconnection and the land for this project. The entire 75 MW of Constable will be owned by PGE, subject to a Build-Deliver Agreement (BDA) with M.A. Mortenson Company (Mortenson)[24] and will provide 44 MW of emissions-free capacity contribution for PGE and our customers.[25]

Q. Who is responsible for the construction and operation of Constable?

A. Mortenson will design and build the entire facility and is responsible for the engineering, procurement, and construction (EPC) of the site. PGE will be responsible for site operation, and to enhance oversight, PGE has engaged Burns & McDonnell as the owner's engineer (OE), who will supervise these activities in collaboration with PGE's dedicated project staff.

Q. How will Constable interconnect and deliver energy to PGE's customers?

A. As mentioned, Constable is being built on-site adjacent to the new 115 kV – 230 kV substation (Evergreen) in Hillsboro, Oregon. The interconnection scope includes the construction of a 115 kV line position at the Evergreen substation (Point of Interconnection (POI)) to accept

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[24] Mortenson is a U.S.-based, top-25 builder, developer and provider of energy and engineering services.

[25] Although Constable has a nameplate capacity or theoretical maximum output of 75 MW, its Effective Load Carrying Capacity (ELCC), which represents the actual capacity that Constable can reliably deliver based on its capabilities and the specific conditions it operates under, is 44 MW.

the generation lead line. There is a position on the Evergreen 115 kV bus that will be utilized as the POI for interconnection with Constable with the addition of a breaker, two disconnect switches, and revenue metering on the generation lead line under an executed Large Generator Interconnection Agreement (LGIA).

Q. When will the Evergreen Substation be placed into service?

A. The Evergreen Substation is being constructed in several phases. The first phase, which includes all of the 115 kV and 230 kV bus work, all of the 230 kV transmission line work, the first 230/115 kV transformer, and a portion of the 115 kV transmission line work, is scheduled to be placed into service by June 30, 2024. The in-service date for the first phase of construction is necessary to ensure that system reliability in Hillsboro is maintained as load continues to grow in the area. Connecting the Constable generator lead line to the breaker position at Evergreen requires only the first phase of the Evergreen project to be complete.

Q. Is the Evergreen substation being constructed to solely accommodate Constable?

A. No. Plans to construct the Evergreen substation were developed as part of the Hillsboro Reliability Project in 2018. The Evergreen substation will provide additional bulk 230/115 kV transformer support in the Hillsboro area and stronger 115 kV connections to neighboring substations to increase reliability in an area with significant load growth. The project also mitigates NERC TPL-001-5 violations identified in the 2018 TPL studies for Horizon bulk power transformers and multiple 115 kV lines in the Hillsboro area.[26]

The planned buildout of the Evergreen substation between 2024 and 2027 will entail three 230/115 kV transformers, two 230 kV transmission connections, five 115 kV transmission

[26] The NERC TPL-001-5 Standard requires PGE to be able to sustain an outage to a single element (line, transformer, etc.) without overloading any facilities or exceeding voltage limits. Without Evergreen, any load growth beyond 210 MW will result in failure to comply with this standard and PGE would incur a NERC violation with fines of up to $1 million per day.

connections, four distribution transformer positions, and the aforementioned breaker position for Constable.

The value of the investment in the Evergreen substation is included in the transmission and distribution capital identified in PGE Exhibit 400 – T&D.

2. Constable Agreements

Q. Please describe the primary agreements that comprise PGE's complete 75 MW ownership share of Constable.

A. PGE's complete ownership share is governed by the BDA. Additionally, several secondary agreements (e.g., LGIA, LTSA, etc.) further define the roles and obligations of the multiple parties.

Q. Please briefly describe the BDA.

A. The BDA provides for PGE to purchase sole ownership of the 75 MW BESS from Mortenson and supporting infrastructure including the project collector substation and electrical collection systems. The BDA is a fixed-price contract to reduce the risk to PGE's customers of schedule delays and construction cost overruns and includes damages protection against project delays.

Q. Please briefly describe the LGIA.

A. The LGIA clarifies and defines the relationship between the Interconnection Customer (PGE's Merchant Function) and the Transmission Provider (PGE's Transmission Function). The LGIA describes the scope, schedule, and estimated cost for the facilities required (i.e., breaker, metering, switches, etc.) to be installed to interconnect Constable. The LGIA also describes ongoing operational responsibilities and legal rights and requirements of the Interconnection Customer and Transmission Provider.

<u>3. Constable Costs and Revenue Requirement</u>

Q. How did you estimate the operating costs and revenue requirement for Constable?

A. We estimated the operating costs and dispatch benefits on an annualized basis, reflecting both costs and benefits for a full year of operations in 2025.

Q. What are the forecast costs associated with Constable?

A. PGE's forecast for Constable consists of the following major categories:

- Gross plant in-service totals approximately $157.1 million, including AFUDC and property taxes.
- Production and transmission O&M expenses total approximately $0.6 million and $0.4 million respectively on an annualized basis.
- Insurance and Administrative & General expenses total approximately $0.1 million.
- The first full year of property taxes for Constable amount to approximately $2.4 million.
- Annualized first-year depreciation expenses total approximately $8.3 million, based on depreciation parameters prepared by Gannett Fleming Valuation and Rate Consultants, LLC, as part of this rate case proceeding.
- Accumulated depreciation and ADIT total approximately ($8.3 million) and ($2.6 million) respectively.
- NVPC totals approximately ($9.6 million) on an annualized basis. This reflects the NVPC benefits associated with energy shaping and provision of capacity for ancillary services, inclusive of maximum cycle constraints, average state of charge requirements, expected availability, and round-trip efficiency losses and is based on

forward curves as of December 29, 2023. Additional detail and supporting documentation are discussed and provided as part of PGE's 2025 power cost filing.

Q. What is the revenue requirement impact of Constable?

A. Including the current forecast of NVPC, the 2025 revenue requirement for Constable is approximately $17.3 million. This does not include the value PGE proposes to amortize to customers for the ITCs that will be received for the project. As discussed below, PGE anticipates amortizing this value through a schedule separate from base rates.

4. Constable Timeline and Milestones

Q. What are the project milestones associated with Constable?

A. Table 4 below lists the estimated construction and testing milestones.

Table 4
Constable Milestones

Milestone	Actual/Scheduled Completion
Notice to Proceed	June 2023 (Complete)
Start of Construction	December 2023 (Complete)
Battery/Inverter Factory Acceptance Testing Completion	April 2024
Mechanical Completion	November 2024
Substantial Completion (COD)	December 2024

Q. When is PGE requesting Constable be included in customer prices?

A. We request that prices recovering Constable's net revenue requirement become effective shortly after a PGE officer has provided an attestation that Constable has been placed in service around the end of December 2024. PGE will update our cost estimates before that time for NVPC.

C. Seaside BESS Project

1. Seaside Technology

Q. Please describe the Seaside BESS project (Seaside).

A. Seaside is a lithium-ion BESS with 200 MW nameplate capacity and four-hour storage capability (i.e., total capacity of 800 MWh) that will be located in North Portland. Seaside is expected to be placed into service in June 2025, and upon completion will interconnect to PGE's Rivergate Substation. The entire 200 MW of Seaside will be owned and operated by PGE, subject to a Build Transfer Agreement (BTA) with Seaside Grid, LLC, a subsidiary of Eolian, and will provide 107 MW of emissions-free capacity contribution for PGE and our customers.[27]

Q. Who is responsible for the construction and operation of Seaside?

A. Seaside Grid, LLC will build the entire facility and PGE will take title to the project upon mechanical completion. Following this, the Engineering, Procurement, and Construction (EPC) contractor (Mortenson) hired by Seaside Grid, LLC, will complete the work through final completion. Additional key parties include an owner's engineer, Burns & McDonnell, hired by PGE.

Q. How will Seaside interconnect and deliver energy to PGE's customers?

A. Seaside will be located approximately a half-mile from the 230 kV interconnection at PGE's Rivergate Substation in North Portland. To facilitate the interconnection, one existing 115 kV transmission line is required to be re-routed to accommodate the new 230 kV generation lead line position dedicated to Seaside. A new 230 kV line position at the Rivergate Substation will be established, complete with necessary components such as breakers, switches, metering, and structures to interconnect the generator lead line.

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[27] Although Seaside has a nameplate capacity or theoretical maximum output of 200 MW, its ELCC, which represents the actual capacity that Seaside can reliably deliver based on its capabilities and the specific conditions it operates under, is 107 MW.

2. Seaside Agreements

Q. Please describe the primary agreements that comprise PGE's complete 200 MW ownership share of Seaside.

A. PGE's ownership is governed by two primary agreements: the BTA and the EPC Agreement. Additionally, several secondary agreements (e.g., LGIA, LTSA, etc.) further define the roles and obligations of the multiple parties.

Q. Please briefly describe the BTA.

A. The BTA provides for PGE to purchase sole ownership in all 200 MW of the Seaside BESS from Seaside Grid, LLC and supporting infrastructure, including the project collector substation and electrical collection systems, at mechanical completion. The BTA is a fixed-price contract to reduce the risk to PGE's customers of schedule delays and construction cost overruns. Of note, the BTA includes damages protection against project delays and includes the scope of constructing the Transmission Provider's Interconnection Facilities and Network Upgrades in accordance with the LGIA between Seaside Grid, LLC and PGE. This work includes installation of a new breaker and associated metering equipment in addition to relocation of a 115 kV overhead line in the Rivergate substation.

Q. Please briefly describe the EPC agreement.

A. The EPC agreement defines the contractor's (i.e., Mortenson) responsibilities and work to be performed with respect to PGE's complete ownership of Seaside, including engineering design requirements, equipment and materials requirements, and construction responsibilities. The EPC agreement is between Seaside Grid, LLC and will be assigned from Seaside Grid, LLC to PGE once Seaside achieves mechanical completion. Seaside Grid, LLC will remain PGE's agent to facilitate the rights and obligations of the EPC on PGE's behalf.

Q. Please briefly describe the LGIA.

A. The LGIA clarifies and defines the relationship between the current[28] Interconnection Customer (Seaside Grid, LLC) and the Transmission Provider (PGE's Transmission Function). The LGIA describes the scope, schedule, and estimated cost for the facilities network upgrades required to be installed to interconnect Seaside. The LGIA also describes ongoing operational responsibilities and legal rights and requirements of the Interconnection Customer and the Transmission Provider.

3. Seaside Costs and Revenue Requirement

Q. What are the forecast costs associated with Seaside?

A. PGE's forecast for Seaside consists of the following major categories:

- Gross plant in-service totals approximately $396.0 million, including AFUDC and property taxes.
- Production and transmission O&M expenses total approximately $2.5 million and $0.5 million respectively on an annualized basis.
- Insurance and Administrative & General expenses total approximately $0.2 million.
- The first full year of property taxes for Seaside amount to approximately $6.6 million.
- Annualized first-year depreciation expenses total approximately $20.9 million, based on depreciation parameters prepared by Gannett Fleming Valuation and Rate Consultants, LLC, as part of this rate case proceeding.
- Accumulated depreciation and ADIT total approximately ($20.9 million) and ($6.4 million) million respectively.

[28] Once PGE takes ownership of Seaside, PGE's Merchant Function will become the Interconnection Customer.

- NVPC totals approximately ($20.7 million) on an annualized basis. This reflects the NVPC benefits associated with energy shaping and provision of capacity for ancillary services, inclusive of maximum cycle constraints, average state of charge requirements, expected availability, and round-trip efficiency losses and is based on forward curves as of December 29, 2023. Additional detail and supporting documentation are discussed and provided as part of PGE's 2025 power cost filing.

Q. What is the revenue requirement impact of Seaside?

A. Including the current forecast of NVPC, the 2025 revenue requirement for Seaside is approximately $49.5 million. This does not include the value PGE proposes to amortize to customers for the ITCs that will be received for the project. As discussed below, PGE anticipates amortizing this value through a schedule separate from base rates.

4. Seaside Timeline and Milestones

Q. What are the project milestones associated with Seaside?

A. Table 5 below lists the estimated construction and testing milestones.

Table 5
Seaside Milestones

Milestone	Actual/Scheduled Completion
Notice to Proceed	June 2023 (Completed)
Start of Construction	May 2024
Battery/Inverter Factory Acceptance Testing Completion	July 2024
Mechanical Completion	January 2025
Substantial Completion (COD)	June 2025

Q. When is PGE requesting Seaside be included in customer prices?

A. We request that prices recovering Seaside's net revenue requirement become effective shortly after a PGE officer has provided an attestation that Seaside has been placed in service in the second quarter of 2025. PGE will update our cost estimates before that time for NVPC.

D. Investment Tax Credit Proposal

Q. How does PGE propose to treat the ITCs associated with Constable and Seaside?

A. Pursuant to the IRA, ITCs are received upfront in the tax year that a project is placed into service (i.e., 2024 or 2025 for Constable and 2025 for Seaside).[29] To maximize the value to PGE customers, because PGE lacks the necessary tax appetite to utilize the ITCs and in anticipation of tax normalization opt-out treatment, we propose to monetize the ITCs in 2025 and return the sales value to customers through a separate tariff schedule over five years with 35% of the total value provided to customers in the first year and reduced by an equal amount each year thereafter until year five, at which point the credits will have been fully amortized. The amortization period assumes interest at the blended treasury rate, consistent with prior Commission Order No. 08-263.

Q. When would PGE anticipate the amortization period for the ITCs to begin?

A. PGE would like to begin refunding this value to customer concurrently with the beginning of the collection of Seaside. This would fully offset the impact of the Seaside price increase in mid-2025, under current ITC assumptions.

Q. Why did you select this method for amortizing the credits to customers?

A. We selected this method to provide a benefit to customers in the face of near-term customer price increases. The method of amortizing at a declining amount each year allows the value

[29] The IRA specifically expanded the Internal Revenue Code Section 48 ITC to include new technologies such as standalone energy storage (i.e., Constable and Seaside).

to taper off smoothly over the course of five years in avoidance of a "price change cliff" for customers.

Q. What is the expected value of the Constable and Seaside ITCs and what amount does PGE expect to return to customers in 2025?

A. The total ITC value awarded is equal to 30% of a project's eligible[30] capital cost. Accordingly, and assuming an approximate 10% discount on the total transfer price,[31] Constable is expected to generate approximately $41.9 million in ITC value and Seaside is expected to generate approximately $105.3 million in ITC value for customers. Additionally, PGE is actively investigating whether Seaside qualifies for the Energy Community benefit (i.e., an additional 10% ITC benefit) as defined in Internal Revenue Code (I.R.C.) Section 48(a)(14). Considering the sale of these ITCs in 2025 and the proposed five-year amortization schedule outlined, PGE anticipates returning approximately $51.5 million of ITC value to customers in 2025.

Q. How did PGE arrive at an approximate 10% discount factor for the sale of the ITCs?

A. A 10% discount factor is an estimate based upon the stipulated agreement in UE 416 for the sale of 2023 Production Tax Credits (PTCs),[32] which was subsequently adopted in Commission Order No. 23-386. However, the actual discount factor and fees would be dependent upon terms agreed to within a sales agreement.

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[30] PGE's current estimated ITC is based upon the forecasted total project cost. This value is preliminary and subject to change based upon final project costs and the percentage of total project cost eligible for the ITC under Proposed Treasury Regulation § 1.48-9

[31] The actual discount and fees to complete the sales are to be determined through the course of negotiations with potential counterparties interested in purchasing the ITCs.

[32] Second Partial Stipulation (Aug 21, 2023) at 3-4.

Q. Has PGE included the value of the ITCs in this rate case proceeding?

A. No. As mentioned, PGE is proposing to return the ITC sales value to customers through a separate tariff schedule. As such, PGE has not included the ITC sales value in the revenue requirements of this rate case proceeding.

VII. Associated Storage

Q. What 2025 changes do you propose for Schedule 122?

A. Schedule 122 is PGE's renewable energy resources automatic adjustment clause (RAAC). PGE recommends a definition of "associated energy storage" for purposes of cost recovery under the RAAC as follows: 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. Specifying that standalone energy storage resources used to firm and shape renewable resources are "associated energy storage" for purposes of the 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. What is the legislative intent of the RAAC-enabling legislation?

A. ORS 469A.120(2)(a) allows for timely recovery in the RAAC for "costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources, costs related to associated electricity transmission and costs related to associated energy storage."[33] Notably, the provision distinguishes generation, transmission, and storage as separate items for RAAC recovery, emphasizing that one item (generation) does not subsume others (transmission and storage). Additionally, the "associated energy storage" language predates widespread co-location trends, evident during the negotiations leading to SB 1547 in 2016. Co-location only recently occurred in Oregon at the utility scale, such as the Wheatridge battery resource in 2022, which is more than six years post-SB 1547 negotiations.

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[33] ORS 469A.120(2)(a)

Thus, it can be inferred that the legislative intent of the RAAC-enabling legislation is to recognize and enable the recovery of costs for each element—generation, transmission, and storage. This interpretation supports the notion that "associated energy storage" encompasses both co-located and standalone solutions, adapting to the evolving landscape of renewable energy technologies and configurations, with standalone storage becoming increasingly critical, especially in light of RPS and HB 2021 decarbonization targets.

Q. How would new renewable resources contribute to RPS compliance?

A. Despite stating in recent CEP/IRP filings that RPS obligations aren't the main driver for incremental resource additions (given the larger and faster requirements imposed by HB 2021 emission reduction targets), the new renewable resources will still play a crucial role in contributing RECs for RPS compliance. These resources, typically with estimated 20 or 30-year life spans for solar/wind, acquired now will be instrumental in meeting PGE's RPS requirements and achieving HB 2021 targets.

Q. Do standalone energy storage resources support PGE's RPS compliance?

A. Yes, standalone energy storage resources play a crucial role in supporting PGE's RPS compliance. Essential for integrating and stabilizing intermittent renewable resource generation, these resources enhance grid reliability and stability. Under HB 2021, thermal resources are no longer a viable resource for PGE to maintain resource adequacy in the long term. Energy storage resources emerge as a vital option, adding dispatchable capacity to ensure system reliability. Despite the increased focus on renewable resource additions due to HB 2021 emission reduction targets, meeting RPS obligations still requires a substantial quantity of renewables. Significant energy storage resources are necessary to integrate intermittent generation into the grid, making them reasonably considered as "associated" and eligible for the RAAC.

Q. How do standalone energy storage resources, like the Constable and Seaside projects connected at the transmission voltage level, contribute to PGE's efforts in integrating growing renewable resources, essential for meeting both RPS and HB 2021 decarbonization targets?

A. Standalone energy storage plays a crucial role by providing capacity-related functions that intermittent renewables lack and reliability functions that are beyond the capabilities of renewables alone, including support for frequency response and contingency reserve—both requirements that are enforceable by NERC. These functions become increasingly vital with the rising penetration of intermittent renewables and the retirement of traditional emitting capacity generators. Large standalone storage resources, exemplified by Constable and Seaside, are instrumental for system reliability as PGE strives to deliver 50 percent renewable electricity to customers by 2040 to meet RPS requirements while simultaneously progressing towards the aggressive emissions-reduction goals mandated by HB 2021.

Q. What are you requesting of the Commission?

A. We request the Commission recognize in this rate case proceeding PGE's proposed definition of "associated energy storage" which includes standalone energy storage resources connected at transmission voltage as "associated energy storage" for purposes of PGE's RAAC Schedule 122. PGE has raised this issue in three prior proceedings[34] and does not yet have clarity on the definition and whether standalone storage resources are permitted by the Commission for

[34] *In the Matter of Portland General Electric Company Draft Storage Potential Evaluation*, Docket UM 1856, *In the Matter of Portland General Electric Company Request for a General Rate Revision,* Docket UE 335, and *In the Matter of Portland General Electric Company Request for a General Rate Revision,* Docket UE 416.

RAAC treatment. A timely decision by the Commission in this docket is necessary to reduce uncertainties and enable the next steps to bring online new resources for customers.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit 501 contains confidential information and is subject to

General Protective Order 23-132

Exhibit 502 contains confidential information and is subject to

General Protective Order 23-132

Exhibit 503 contains confidential information and is subject to

General Protective Order 23-132

Plant	2023 Actuals	UE 416 Approved MMAs (2024 Budget)	2025 FILE	2025 GRC Revised	Variance (2023 Actuals-2025 revised)	Variance (2024 Budget-2025 FILE)	Annualized Variance (2024 GRC-2025 GRC)	Variance 2025 FILE vs 2025 GRC Revised
Carty	6,849,666	7,170,646	7,170,646	7,592,181	742,516	-	421,536	421,536
Coyote	3,464,004	1,875,942	1,878,465	1,832,777	(1,631,227)	2,523	(43,165)	(45,688)
PW1	3,829,313	6,228,562	6,228,562	6,329,137	2,499,823	-	100,575	100,575
PW2	961,005	850,936	850,939	959,537	(1,468)	3	108,601	108,598
KB Pipeline Pigging	59,066	26,764	26,764	(3,441)	(62,507)	-	(30,205)	(30,205)
Total	**15,163,054**	**16,152,849**	**16,155,375**	**16,710,191**	**1,547,137**	**2,526**	**557,342**	**554,816**

PGE Accounts	2023 Actuals	UE 416 Approved MMAs (2024 Budget)	2025 FILE	2025 GRC Revised	Variance (2023 Actuals-2025 revised)	Variance (2024 Budget-2025 FILE)	Annualized Variance (2024 GRC-2025 GRC)	Variance 2025 FILE vs 2025 GRC Revised
MMAs in Account 4560002	(3,723,174)	(4,748,975)	(4,972,852)	(4,972,852)	(1,249,677)	(223,876)	(223,876)	-
MMAs in Generation O&M Accounts	18,886,228	20,901,825	21,128,227	21,683,043	2,796,814	226,402	781,218	554,816
check	-	-	-	-	0	0	(0)	(0)

PGE Exhibit 200 (Revenue Requirement) MMA Adjustment in Generation O&M		
2025 FILE	2025 REVISED	Adjustment
16,155,375	16,710,191	**554,816**

1. Total MMA amounts in Generation O&M Accounts and Account 4560002 (Other Revenue)

PGE Exhibit 500 (Generation O&M) MMA Adjustment[2]		
2025 FILE	2025 REVISED	Adjustment
21,128,227	21,683,043	**554,816**

2. Includes only Generation O&M Accounts

Exhibit 505 contains highly confidential information

Information to be provided pending approval of a modified protective order

Exhibit 506 contains highly confidential information

Information to be provided pending approval of a modified protective order

Exhibit 507 contains highly confidential information

Information to be provided pending approval of a modified protective order

Exhibit 508 contains highly confidential information

Information to be provided pending approval of a modified protective order

Exhibit 509 contains highly confidential information

Information to be provided pending approval of a modified protective order

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Josh Figueroa
Christopher Liddle

February 29, 2024

Table of Contents

I. Introduction

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

A. My name is Christopher A. Liddle. I am the Senior Director, Risk Management and Assistant Treasurer at PGE. My qualifications are provided at the end of this testimony.

My name is Josh Figueroa, and I am a Senior Associate of The Brattle Group, whose business address is One Beacon Street, Suite 2600, Boston, Massachusetts, 02108. PGE asked me to estimate the cost of equity PGE should be allowed an opportunity to earn on the equity portion of its rate base for the period starting January 1, 2025. I directly sponsor the testimony found in Section IV. My qualifications are provided in Exhibit 603.

Q. What is the purpose of your testimony?

A. Our testimony describes PGE's proposed authorized cost of capital and capital structure for the 2025 test year. PGE's cost of capital and capital structure were last approved in Public Utility Commission of Oregon (Commission) Order No. 23-386 in October 2023.

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. Guidance regarding the appropriate authorized cost of capital is provided by the *Bluefield* and *Hope* United States Supreme Court decisions, as well as ORS 756.040.

Q. What is PGE's requested overall cost of capital for this filing?

A. We request a 7.189% weighted average cost of capital for the 2025 test year. This cost of capital reflects PGE's updated request for return on equity (ROE) of 9.750%, its currently authorized capital structure of 50% debt and 50% equity, and an updated long-term cost of debt of 4.628%. 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%	4.628%	2.314%
Common Equity	$4,183,009	50%	9.750%	4.875%
Total	**$8,921,809**	**100%**		**7.189%**

[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).

Q. How is the remainder of your testimony organized?

A. After this introduction, our testimony has six sections:

- Section II – Overview of Financial Landscape
- Section III – Cost of Long-Term Debt
- Section IV – Cost of Equity
- Section V – Capital Structure
- Section VI – Summary
- Section VII – Qualifications

II. Overview of Financial Landscape

A. Financial Goals and Performance

Q. What is PGE's overall financial goal?

A. PGE's overall financial goal is to provide sufficient capital and liquidity to fund PGE's operations at the least cost and least risk to customers. While this is always a key financial goal, it is even more critical to maintain a strong financial position and access to low-cost capital as we invest to meet the decarbonization targets set forth in House Bill 2021.

Q. Does PGE have additional financial goals?

A. Yes. Aligned with PGE's overall financial goal, PGE strives to protect against unforeseen negative changes in cash flows by managing daily cash and liquidity needs. To do this, PGE relies on its revolving credit facility, commercial paper, long-term debt, and common equity.

Q. What tools do you use to meet your financial goals?

A. PGE maintains solid financial performance by:

- Maintaining investment grade credit ratings.
- Accessing financial markets at reasonable terms to provide liquidity for operations and capital expenditures.
- Achieving an actual ROE commensurate with the ROE achieved by a group of utilities with similar characteristics, service territory, and business risks.
- Maintaining a capital structure of approximately 50% debt and 50% equity over time.
- Setting retail prices at a level sufficient to recover prudently incurred costs, including an overall return on utility investment, while taking into account price impacts given the economic conditions facing PGE's customers.

In addition, PGE manages wholesale counterparty and retail customer credit risk to protect our customers and PGE. We engage in liquidity management to meet our obligations and support PGE's operations. Finally, PGE strives to maintain a strong financial position in support of targeted investments, which aids us in meeting 2030 decarbonization mandates.

Q. Does access to low-cost capital benefit customers?

A. Yes. Our customers want reliable, clean energy at an affordable price that is transmitted safely to them. To invest in clean energy resources and infrastructure that strengthens the reliability of our grid, PGE needs access to capital. For example, recent capital raised by PGE through debt and equity offerings is funding the Constable and Seaside battery energy storage projects discussed in Exhibit 500, and to improve the safety of our service territory through the wildfire mitigation program, and the innovation and efficiency of our grid through automation.

Vertically integrated utilities utilize constant infusions of capital to grow, maintain, and adapt the business to modern times. As such, access to the lowest-cost capital possible is imperative for both the business and our customers.

Q. How does solid financial performance impact PGE's access to low-cost capital?

A. Investors choose their investments based on risk and reward. Solid financial performance leads to a higher credit rating, a higher share price, and positive investor sentiment. These factors improve PGE's ability to issue new shares of equity at a higher price and issue debt at a lower interest rate.

Q. Does PGE's financial performance impact its desired long-term capital structure?

A. Yes. PGE's desired long-term capital structure is 50% equity and 50% long-term debt. We believe that the 50% equity in PGE's authorized capital structure helps it better withstand difficult situations, such as under-earning due to events outside of PGE's control and continued pressure on equity capitalization ratios due to imputed debt.

Q. Why is it important for PGE to maintain investment grade credit ratings?

A. Investment grade credit ratings allow PGE to secure financing for both debt and equity at reasonable rates and to maintain access to wholesale energy markets with the best prices for customers. Credit ratings are the primary measure used by investors and counterparties to evaluate the creditworthiness of a company and its ability to meet its financial obligations. Ratings affect the number and type of investors and the cost of the company's debt. The higher the credit rating, the lower the cost of debt and the lower the cost of capital passed onto PGE's customers. An investment grade credit rating also ensures access to low-cost capital during times of market volatility; for example, during the COVID-19 global pandemic, credit spreads for lower rated companies were significantly wider.

Without an investment grade credit rating, PGE's access to financing would be limited, at higher rates, and PGE would have to provide significantly more collateral to its counterparties (and may lose the ability to trade with some counterparties) in the wholesale power and gas markets. This would result in higher costs to PGE's customers.

Q. What does PGE do to maintain its investment grade credit rating?

A. PGE's credit rating is a function of its financial performance, which is driven by PGE's retail prices, including the return embedded in retail prices, and the ability to manage costs. Rating agencies, as well as equity investors, expect companies to meet certain financial performance standards to achieve an investment-grade credit rating, as demonstrated in the financial and liquidity ratios that the rating agencies publish. PGE takes steps to ensure that its financial performance continues to place it within the range of the appropriate financial ratios.

PGE accomplishes this through continuous financial management that includes: closely monitoring budgets; minimizing the cost to finance operations through the optimal use of revolving credit line; long-term debt and equity; closely monitoring capital structure; and analyzing counterparty risks in order to take appropriate mitigation measures. These measures help PGE maintain financial performance levels necessary for investment-grade credit ratings.

Q. What are PGE's current bond ratings?

A. PGE's bond ratings for secured long-term debt (First Mortgage Bonds or FMBs) are A1 from Moody's and A from Standard & Poor's (S&P). Ratings for unsecured debts are A3 and BBB+. PGE's credit ratings were recently affirmed and are provided in PGE Exhibit 602.

Q. Have rating agencies recently changed outlooks on PGE?

A. Not since the conclusion of Docket No. UE 416 (UE 416), PGE's 2024 test year general rate case. Both S&P and Moody's maintain a 'stable' outlook for PGE in their most recent 2023 reports.[1]

Q. How do rating agencies evaluate PGE's creditworthiness?

A. Creditworthiness describes a company's overall financial health and ability to repay all financial obligations. Both Moody's and S&P focus on the quantitative and qualitative areas of a company when evaluating creditworthiness and establishing credit ratings.

For example, Moody's established credit ratings based on four key factors: 1) 25% regulatory framework; 2) 25% ability to recover costs and earn returns; 3) 10% diversification which includes market position and generation and fuel diversity; and 4) 40% financial strength and key financial metrics (this includes ratios on cash flow, debt service coverage, leverage, and interest coverage).

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[1] "Portland General Electric Company: Update to Credit Analysis." Moody's 18 April 2023; "Portland General Electric Co: Research Update" S&P 14 December 2023.

Q. What recent concerns have been expressed by the rating agencies regarding PGE's creditworthiness?

A. In the April 2023 report[2] Moody's noted a downgrade could occur due to "a deterioration in the credit supportiveness of the Oregon regulatory environment as evidenced by partial or delayed recovery of cost deferrals or diminished support for carbon transition investments." Moody's also noted that PGE has been pressured by several one-time costs that led to a substantial increase in cost deferrals, the recovery of which was dependent on OPUC review at a later regulatory proceeding. A third concern noted by Moody's was that PGE is "exposed to unrecoverable power costs via asymmetric customer sharing of actual costs."

In their December 2023 report, S&P notes that a key risk for PGE is its susceptibility to wildfires. S&P stated that "about 9% of its service territory has been identified as high risk fire zone, with a little over 2% of its customers as inhabitants which introduces risk for the company regarding wildfires, some of which could become materially significant."[3] Key areas of focus for S&P include monitoring ongoing legal proceedings in the state and "the risk of cost recovery related wildfire litigation…."[4] A second concern noted by S&P was that "[a] rating downgrade could result if PGE's key financial metrics do not recover, including if the company's ratio of CFO pre-WC to debt remains below 18% in 2023."[5]

Q. What is CFO pre-WC to debt and how could this metric be driven downward?

A. Cash flow from operations before changes in working capital (CFO pre-WC) to debt is a credit metric that measures the cash generating ability of the company through operations, primarily from its customers, relative to debt, as a ratio of cash flow to debt. This financial ratio is an

[2] "Portland General Electric Company: Update to Credit Analysis." Moody's 18 April 2023.
[3] Portland General Electric. RatingsDirect Full Analysis. S&P Capital IQ. 14 December 2023.
[4] Ibid.
[5] *Id.*

important indicator of the financial strength and liquidity of a regulated utility. Many actions could decrease CFO pre-WC to debt. Most notably from a financing perspective, changes in PGE's capital structure could impact this metric. Specifically, an increase in debt would lower this financial ratio. PGE is requesting to maintain its 50/50 capital structure, which directly impacts PGE's ability to achieve a CFO pre-WC to debt above 18%.

Q. What would a PGE rating downgrade by Moody's mean for PGE customers?

A. A rating downgrade from Moody's would likely mean higher prices for PGE customers. A lower credit rating would increase the cost of debt and impact PGE's ability to attract debt and equity capital at a reasonable price, leading to higher overall costs for customers.

Q. You noted that rating agencies consider the "regulatory environment" when determining a company's rating. Can you provide some additional detail?

A. Yes. Rating agencies place a high value on stability, predictability, consistency, and transparency in how a utility is regulated. Both Moody's and S&P consider regulatory policy a key factor in their determination of a utility's creditworthiness. Moody's places 50% weight on the "Regulatory Framework and Ability to Recover Costs and Earn Returns" and notes that a regulated utility's regulatory environment "greatly influences the stability and predictability of its cash flows."[6] S&P indicates that "[t]he regulatory framework is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[7]

The ability to promptly recover prudently incurred costs is extremely important to maintaining a stable, investment-grade credit rating because a delay may cause financial

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[6] "Rating Methodology Regulated Electric and Gas Utilities" Moody's. 23 June 2017.
[7] "Key Credit Factors for the Regulated Utilities Industry" Standard & Poor's. 19 November 2013.

stress. Regulatory decisions are critical to protect the Company's credit quality, its ability to recover its costs, and to earn a fair and reasonable return.

Q. Have the rating agencies and investors shown concern regarding PGE's regulatory mechanisms?

A. Yes. Both PGE's rating agencies and investors have expressed concern with PGE's earnings volatility due to one-time write-offs, the size and asymmetry of the deadbands on the Power Cost Adjustment Mechanism (PCAM), and Oregon's regulatory policies, in general.

In addition to concerns expressed by the rating agencies and investors, financial analysts have also expressed these same concerns regarding the PCAM. Given PGE's PCAM structure results in a higher level of earnings volatility, investors will compare PGE to other decarbonizing utilities that have lower risk due to the straight pass-through of power costs.

Q. In prior years, PGE's rating agencies and investors have been concerned by one-time write-offs. Has PGE had any recent significant one-time write-offs?

A. Yes. On April 25, 2022, Commission Order No. 22-129 applied an earnings test at 20 basis points below PGE's authorized ROE to the 2020 Labor Day Wildfire Emergency (Wildfire Emergency) and 2021 February Ice Storm Emergency (Ice Storm Emergency) deferrals. This left PGE unable to recover approximately $14 million in expenses directly resulting from these catastrophic events and forced PGE to write-off the amount. PGE's stock price fell immediately, and by May 5, 2022, PGE's stock was underperforming peer companies by 6.8%. PGE's share price did not begin to improve relative to utility peers until after May 27, 2022, when the Commission issued an order[8] granting PGE's motion for clarification

[8] *See* Docket No. UE 394, Order No. 22-188 (May 27, 2022), granting PGE's Motion for Clarification.

that the earnings test ruling would not set precedence for major emergencies in the future; however, valuation still significantly underperformed relative to prior levels for some time.

Q. How did the rating agencies and investors react to the emergency events write-off?

A. While the rating agencies did not make any direct statement after the write-off of the Wildfire Emergency costs, Moody's March 2022 report, issued just before the write-off which highlighted the importance of full recovery of these costs to PGE's credit rating. The reaction from investors was more immediately seen through the sharp decrease in PGE's share price and the research written by investment analysts.

Q. What else do the rating agencies consider when selecting a rating for PGE?

The rating agencies also consider the liabilities associated with long-term Power Purchase Agreements (PPAs), including Qualifying Facility (QF) contracts, as imputed debt on the balance sheet, which increases the company's debt-to-equity ratios.

Q. What challenges does PGE face in connection to imputed debt?

A. PGE faces significant risks and uncertainties due to imputed debt from PPAs. S&P "imputes" additional debt to PGE's capital structure based on the payments under long-term PPAs. S&P views these as quasi-debt instruments, making an adjustment to the capital structure to reflect the additional leverage. As PGE acquires more long-term capacity contracts and QF contracts, this imputed debt adjustment could increase the debt ratio enough to create a quantitative trigger for potential ratings downgrades.

Q. Overall, how does PGE manage its long-term cost of capital?

A. PGE prefers FMBs as the primary form of debt because they have a lower cost than unsecured alternatives. PGE evaluates private placement market rates, bank term loans, commercial paper, and a delayed draw/forward structure to arrive at the lowest reasonable financing costs available at the time of PGE's financing need.

Q. Does PGE have any debt or equity issuances on the horizon?

A. PGE's long-term goal is to be at a 50/50 debt-equity ratio. In April 2023, PGE filed an at-the-market (ATM) program which allows the Company to raise capital over time by selling shares into the market on an as-needed-basis. The ATM also uses a forward agreement which allows PGE to lock in today market price without actually issuing any shares until a future date of its choosing. The Company began selling under the ATM in May 2023 through present day. PGE is anticipating that we will continue to issue equity in 2024 and beyond, to finance additional capital investments in clean energy to meet 2030 decarbonization goals.

PGE issued $450 million of debt in February of 2024, and through the 2025 test year, PGE is anticipating issuing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to finance ongoing company investments.

B. Management of Customer and Counterparty Credit Risks

Q. Why is it important for PGE to manage customer credit risks?

A. It is important to manage credit risks to limit losses associated with non-payment of customers' bills.

Q. What customer credit risks does PGE face?

A. PGE's energy deliveries and revenues are subject to industry and customer-specific risks and uncertainty, including potential shutdown of customer facilities, curtailment of customers' operations, or changes in capacity because of economic or specific circumstances.

Q. How does PGE manage its customer credit risk exposure?

A. For non-residential customers, PGE manages customer credit risk by proactively monitoring customer payment habits with PGE as well as reviewing commercial credit reports such as Dun and Bradstreet, Moody's, S&P, and Credit Risk Monitor. If warranted, PGE may collect deposits from high-risk commercial customers to minimize loss in the event of a default.

PGE performs credit reviews of its customers, particularly large customers, and associated industries annually. Other items, such as negative company and industry news, a public debt rating downgrade, or consistent late payment trends with PGE may trigger a credit review. PGE's load forecasters work closely with its Key Customer Managers to gain a better understanding of the forecasts provided by large customers and the potential consequences on PGE's retail load. After review, PGE determines the appropriate deposit required from a large customer—typically up to one-sixth of the annual bill.

Q. How does PGE manage counterparty risk?

A. PGE manages wholesale power transaction counterparty risk using the same methods as for large customers. Specifically, PGE performs credit reviews of wholesale power counterparties, both purchasers and sellers, and determines the appropriate amount of collateral required from a counterparty based on their credit risk profile. PGE also sets a minimum credit ratings threshold below which it will not trade with a counterparty.

Q. How does PGE manage supplier financial viability?

A. PGE manages its supplier financial viability through a review of supplier financials, and the use of external financial reporting and evaluation providers.

C. Liquidity Management

Q. Describe PGE's strategy for liquidity management and the revolving credit facility.

A. PGE's strategy is four-fold:

1) Carry sufficient credit levels to support both operational and power supply needs over a five-year, forward-looking time horizon.
2) Achieve a designation of adequate or better from rating agencies (based on Moody's and S&P's interpretation of PGE's liquidity).
3) Fund short-term debt requirements using commercial paper or revolving credit facility loans as appropriate. Issue letters of credit in lieu of cash collateral if the pricing is advantageous and to manage volatility in power markets and resulting margin exposure.
4) Manage market exposure related to maturing lines of credit by replacing them one year prior to maturity.

Q. Has PGE separately analyzed its revolving lines of credit requirements?

A. Yes. PGE periodically analyzes its revolving lines of credit requirements separately for power supply and other operational needs, the sum of which is the total liquidity requirement for PGE. This approach enables PGE to ensure liquidity for power and gas procurement efforts to meet collateral requirements, while maintaining sufficient liquidity for other operations.

Q. When did PGE last perform such an analysis and what were the results of that analysis?

A. PGE analyzed its revolving lines of credit requirements in August 2023. As a result of that analysis, PGE increased its revolving credit facility by $100 million to $750 million and kept the additional $100 million accordion feature. PGE also requested and was approved for a $100 million increase to its letter of credit facilities, for an aggregate total of $320 million. At present, PGE's $750 million revolver and $320 million letter of credit facilities protect against our modeled power supply risk and mitigate the risk of restricted capital market access.

However, given PGE's expected capital expenditures to support decarbonization, an increase in the size of the revolver may be needed in future years.

Q. Did you determine how the results of this analysis would affect PGE's ratings?

A. Yes. For Moody's criteria, PGE's liquidity profile would be rated "adequate" in 2022 and 2023. For S&P, PGE would be rated "adequate" in 2022 and 2023 based on its rating criteria.

III. Cost of Long-Term Debt

Q. What is PGE's cost of long-term debt?

A. PGE's 2025 cost of long-term debt is expected to be 4.628% Confidential PGE Exhibit 601 presents the amount and effective cost of outstanding long-term debt for the test year. This includes bond issuances as of February 1, 2024, and expected bond issuances through 2025.

Q. How did you calculate the cost of long-term debt for 2025?

A. The full amount and cost for each issuance of debt outstanding at year end is included in the calculation with the applicable adjustments to debt as approved in Commission Order No. 22-129 when calculating the amount of debt outstanding. We then multiply the amount outstanding by the effective interest rate for each bond issuance. The effective interest rate represents the internal rate of return for each of the cash flows associated with each debt issuance, including all unamortized call premiums and issuance expenses for debt issuances replaced before maturity with less expensive financings. Table 2 summarizes PGE's cost of long-term debt for the 2025 test year.

Table 2
PGE's Cost of Long-Term Debt ($000)

	2025 Forecast
Principal Amount	$4,738,800
Annual Interest Cost	$215,087
Effective Interest Rate	**4.628%**

Q. What future debt issuances did you include in your analysis?

A. We expect to issue up to $720 million in long-term fixed rate debt during 2024 and $100 million in long-term fixed rate debt during 2025. These full amounts are included in our current best estimate.

Q. What is the expected term, coupon rate, and issuance cost for the bonds to be issued in 2024 and 2025?

A. In February 2024, PGE issued $450 million of FMBs which included the following tranches: $100 million maturing in 2029 with a coupon of 5.15%, $100 million maturing in 2034 with a coupon of 5.36% and $250 million maturing in 2054 with a coupon of 5.73%.

PGE also expects to issue $130 million of FMBs in Q3 and $140 million of FMBs in Q4 2024. We will update our cost of debt as actual terms become available. The estimated coupon rates are based on an indicative new issuance pricing analysis, which includes a current estimated credit spread provided by a subset of PGE's investment banks and a forecast of treasury rates from the Bloomberg Terminal Bond Yield Forecast (BYFC) screen.

Q. Is there any long-term PGE debt maturing in 2024 and 2025?

A. Yes. PGE has $80 million of FMBs maturing in 2024.

IV. Cost of Equity

A. Summary of ROE Conclusions

Q. Please summarize your recommended ROE for PGE.

A. My recommended range of ROE for PGE is 10.25% to 11.25% (midpoint 10.75%) on the equity portion of its regulated rate base at the requested 50.0% equity capital structure. My recommendation is based on the standard cost of capital estimation models, including the Capital Asset Pricing Model ("CAPM"), two versions of the Discounted Cash Flow ("DCF") model, as well as the Implied Risk Premium model. The model results were considered alongside an analysis of PGE's business risk relative to that of the vertically integrated electric utility proxy companies in my Electric Sample. Figure 1 summarizes the reasonable range of ROE estimates for the Electric Sample at PGE's requested 50.0% equity capital structure.

Figure 1
Summary of Reasonable Ranges at 50% Equity

	Electric Sample
CAPM/ ECAPM	11.0% to 11.5%
DCF	9.5% to 11.25%
Risk Premium	10.5%

PGE is requesting an allowed ROE of 9.75% on the equity portion of its rate base due to customer affordability considerations. The requested 9.75% ROE is conservative given the results of my analysis and assessment of PGE's business risks relative to that of the proxy companies, however PGE's requested ROE is supported by the low-end of the DCF reasonable range. PGE's requested ROE of 9.75% also recognizes that the cost of capital has increased since the Commission awarded PGE its current allowed ROE (9.5%). The requested ROE is also consistent with the recent average and median allowed ROE for vertically integrated electric utilities.[9] I note that this recommendation does not consider nor add to the ROE to account for PGE's business risk profile, which I find to be higher than that of the proxy companies due to the asymmetric risk introduced by the PCAM, PGE's smaller size, and its exposure to wildfire risks.

Q. How is the remainder of your ROE testimony organized?

A. First, I discuss the principles and approaches to estimating the cost of equity capital. Second, I discuss recent developments in capital market conditions and their impacts on the cost of capital. Third, I present the results from the cost of equity models and the reasonable ranges of ROE estimates for PGE. Fourth, I discuss the relative business risks faced by PGE and the proxy companies. Finally, I summarize my conclusions and ROE recommendation.

B. Cost of Capital Principles and Approach

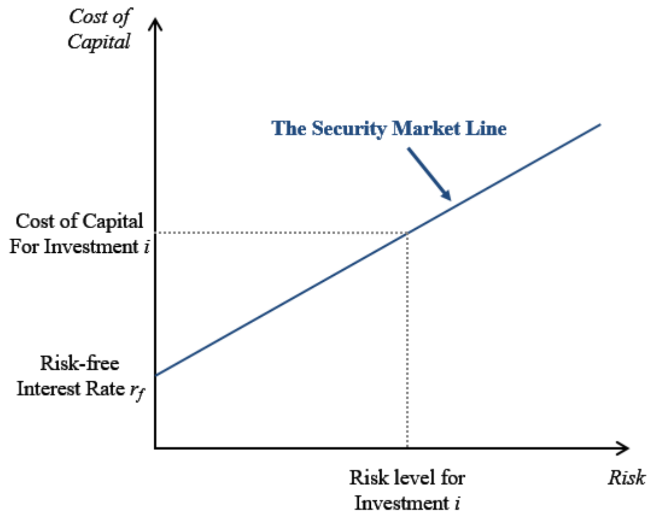
1. Risk and the Cost of Capital

Q. How is the "cost of capital" defined?

A. The cost of capital is defined as the expected rate of return in capital markets on alternative investments of equivalent risk. Put differently, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The definition of the cost of capital recognizes a tradeoff between risk and return represented by the "security market risk-return line," as depicted in Figure 2. The higher the risk, the higher the cost of capital required.

[9] *See* S&P Capital IQ, "Past Rate Cases," data as of January 20, 2024. Specifically: 2022 average 9.75%, median 9.70%; 2023 average 9.80%, median 9.70%; 2024 average 9.59%, median 9.75%.

Figure 2
The Security Market Line



Q. What factors contribute to systematic risk for an equity investment?

A. When estimating the cost of equity for a given asset or business venture, two categories of risk are important. The first is business risk, which is the degree to which the cash flows generated by the business vary in response to moves in the broader market. In context of the CAPM, business risk can be quantified in terms of an "asset beta" or "unlevered beta." For a company with an asset beta of 1, the value of its enterprise will increase (decrease) by 1% for a 1% increase (decline) in the market index. The second category of risk, financial risk, depends on how the business is financed. Later, I explain how financial risk affects the systematic risk of equity.

Q. What are the guiding standards that define a just and reasonable allowed rate of return on rate-regulated utility investments?

A. The seminal guidance on this topic was provided by the U.S. Supreme Court in the *Hope* and *Bluefield* cases,[10] which found that:

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[10] *Bluefield Water Works & Improvement Co. v. Public Service Com'n of West Virginia*, 262 U.S. 679 (1923) ("Bluefield"), and *Federal Power Com'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope").

- The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks;[11]
- The return should be reasonably sufficient to assure confidence in the financial soundness of the utility; and
- The return should be adequate, under efficient and economical management for the utility to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[12]

Q. How does the standard for a just and reasonable relate to the cost of capital?

A. The first component of the *Hope* and *Bluefield* standard is directly aligned with the financial concept of the opportunity cost of capital[13]—that the cost of capital is the rate of return investors can expect to earn in capital markets on alternative investments of equivalent risk.

By investing in a regulated utility, investors are tying up some capital in that investment, foregoing alternative investment opportunities. Investors are incurring an "opportunity cost" equal to the returns available on those alternative investments. The allowed return on equity needs to be at least as high as the expected return offered by alternative investments of equivalent risk or investors will choose those alternatives instead. Otherwise, the utility's ability to raise capital and fund its operations will be negatively impacted.

Q. Please summarize how you considered risk when estimating the cost of capital.

A. To evaluate comparable business risk, I looked at a proxy group of regulated, vertically integrated, electric utilities (the "Electric Sample"). The electric utilities I consider have a high

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[11] Hope, 320 U.S. at 603.

[12] Bluefield, 262 U.S. at 680.

[13] A formal link between the opportunity cost of capital as defined by financial economics and the proper expected rate of return for utilities was developed by Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases*," Bell Journal of Economics & Management Science* 3:58-97 (1972).

proportion of regulated assets and revenue subject to regulation. Additionally, they all have a network of assets that are used to serve end-use customers and they are capital intensive (meaning that each dollar in revenue requires substantial investment in fixed assets).

Further (as explained in the next sub-section), I analyzed and adjusted for differences in financial risk due to different levels of financial leverage among the proxy companies and the regulatory capital structure that will be applied to PGE for ratemaking purposes. To determine where in the estimated range of PGE's cost of equity reasonably falls, I compared the business risk of PGE to that of the proxy group companies.

2. Financial Risk and the Cost of Equity

Q. How does capital structure affect the cost of equity?

A. Debtholders in a company have a fixed claim on the assets of the company and are paid prior to the company's owners (equity holders) who hold the inherently variable residual claim on the company's operating cash flows. Because equity holders only receive the profit that is left over after the fixed debt payments are made, higher degrees of debt in the capital structure amplify the variability in the expected rate of return earned by equity holders. This phenomenon of debt resulting in financial leverage for equity holders means that, all else equal, a greater proportion of debt in the capital structure increases risk for equity holders, causing them to require a higher rate of return on their equity investment, even for an equivalent level of underlying business risk.

Q. How do differences in financial leverage affect the estimation of the cost of equity?

A. The CAPM and DCF models 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 (market values).

The authorized ROE is applied to the regulatory equity portion of PGE's rate base. Because the cost of equity is measured using a group of proxy companies, it may well be the case that these companies are financed with a different debt and equity proportion than the proportion the Commission allows in PGE's rate base. Specifically, the CAPM and DCF models measure the cost of equity using market data and consequently are measures of the cost of equity using the proportion of debt and equity that is inherent in that data. Therefore, I consider the impact of any difference between the financial risk inherent in those cost of equity estimates and the capital structure used to determine PGE's required return on equity.

Differences in financial risk—due to the different degree of financial leverage in PGE's regulatory capital structure compared to the capital structures of the proxy companies—mean that the equity betas measured for the proxy companies must be adjusted before they can be applied in determining PGE's CAPM return on equity. Similarly, the cost of equity measured by applying the DCF models to the proxy companies' market data requires adjustment if it is to serve as an estimate of the appropriate allowed ROE for PGE at the regulatory capital structure the Commission grants.

Importantly, taking differences in financial leverage into account does not change the value of the rate base. Rather, it acknowledges the fact that a higher degree of financial leverage in the regulatory capital structure imposes a higher degree of financial risk for an equity investment in PGE's rate base than is experienced by equity investors in the market-traded stock of the less leveraged proxy companies.

Q. How specifically do you consider financial risk in your analysis of the cost of equity using market data for the proxy companies?

A. The impact of financial risk is considered in an analysis of the cost of equity using market-based models such as the DCF and CAPM in several ways.[14] One approach was developed by Professor Robert Hamada who estimated the cost of equity using the CAPM and made comparisons between companies with different capital structure using beta. A second approach, applicable to both CAPM and DCF, is based on the academic research of Professors Franco Modigliani and Merton Miller,[15] which determines the after-tax weighted-average cost of capital (or overall cost of capital) for the proxy group using the equity and debt percentages as the weight assigned to the cost of equity and debt. I provide additional details on these methodologies in the Technical Appendix to my testimony.[16]

Q. Does the OPUC Staff's ROE methodology recognize the importance of accounting for differences in financial leverage?

A. Yes, OPUC Staff (Staff) recognizes the importance of accounting for financial leverage and commonly relies on a version of the Hamada method to assess the impact of leverage on the cost of equity.[17] In a prior PGE docket, Staff testified:

> ***Q. What accounts for differences in peer capital structures?***
>
> *A. Each [DCF] model employs the Hamada equation to calculate an adjustment for differences in capital structure between each peer utility and the PGE-proposed and Staff-assumed capital structure for PGE. When few peer utilities are available, <u>the Hamada equation ensures Staff's analysis addresses differences in peer utility capital structures.</u>*
>
> ***Q. Does PGE use a different variant of the Hamada equation in the Company's modeling?***

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[14] The impact of financial leverage on the Risk Premium Model needs to be considered separately as it uses regulatory data rather than market data.

[15] Franco Modigliani and Merton H. Miller, "The cost of capital, corporation finance and the theory of investment," American Economic Review, 48 (1958) at 261-297.

[16] *See* PGE Exhibit 604.

[17] Docket No. UE 319, Staff/500, Muldoon/15 (Jun 16, 2017).

> *A. Yes, and I appreciate PGE's analysis in this regard. Staff and the Company are addressing like issues with similar thinking. Though PGE and Staff may not agree, they are both in the same sporting arena.*[18]

Specifically, Staff's methodology implements the Hamada adjustment to determine a "premium" above or below *Value Line*'s reported beta. Staff then applies this Hamada-derived premium to the results of the DCF model.[19] While I disagree with Staff's non-standard methodology of implementing the Hamada adjustment, it shows that Staff recognizes the impact that differences in financial leverage can have on the cost of capital.

3. Capital Market Conditions and the Cost of Capital

Q. Why are capital market conditions important in determining PGE's ROE?

A. Capital market conditions are important to cost of equity estimation methodologies and can affect the inputs to the cost of equity models. For example, the risk-free rate is an input to the CAPM and Risk Premium model, so recent and expected developments in government bond yields are important to assess the validity of any measure of the risk-free rate. The market equity risk premium ("MRP") (e.g., volatility and changes in investors' risk perceptions) is vital for accurate determinations of the ROE. In addition, inputs to the DCF models are affected by the economy as economic growth will affect utility growth rates and stock prices. Consequently, the capital market developments affect the growth rates, dividend yield, and assessment of estimates' reasonableness.

Q. Please provide a summary of recent developments in the capital markets.

A. Several key capital market factors, such as inflation rates and bond yields, remain elevated due to ongoing economic, financial, and geopolitical uncertainties. Inflation, as measured by the Consumer Price Index (CPI), reached a recent high of 9.1% in June 2022 before declining

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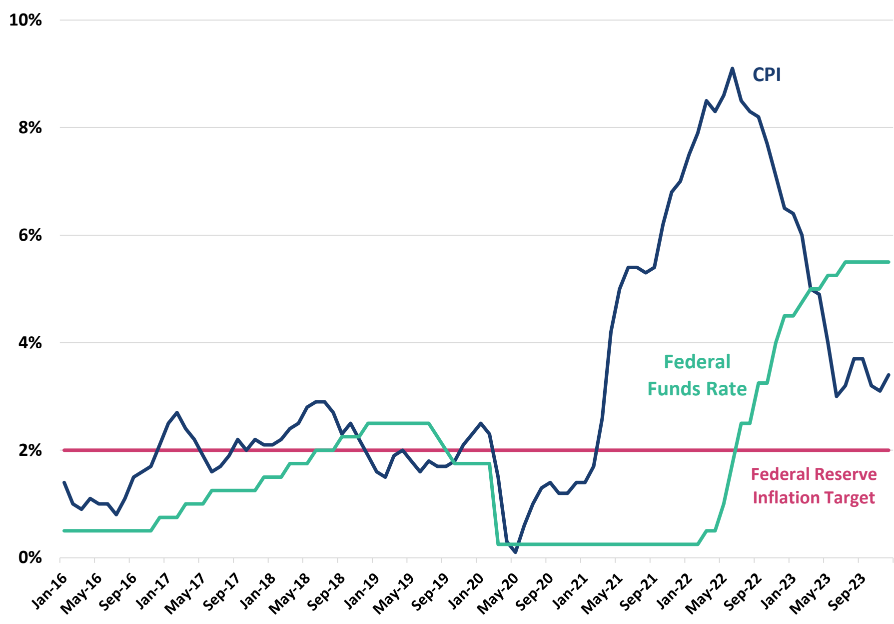
18 *Ibid*. Clarification and emphasis (underline) added.
19 *Id.*, p. 23 and PDF pp. 194-195. (Staff/502 Muldoon/5).

to 3.4% in December 2023[20]—significantly above the Federal Reserve's inflation target of 2.0% on average— after the Federal Reserve began tightened monetary policy by increasing the Federal Funds Rate and reducing the size of balance sheet (*i.e.*, Quantitative Tightening).[21] Figure 3 depicts recent trends in the CPI and the Federal Funds rate.

Figure 3
Consumer Price Index and Federal Funds Rate[22]



Notably from looking at Figure 3, inflation has persisted above 3.0% since June 2023 despite the Federal Reserve maintaining the Federal Funds rate at 5.50%.[23] After the December 2023 FOMC meeting, Chair Powell made the following remarks:

> *While we believe that our policy rate is likely at or near its peak for this tightening cycle, the economy has surprised forecasters in many ways since the pandemic, and going progress…towards our 2 percent inflation objective is not assured. We are prepared to tighten policy further if appropriate. We're committed to achieving a stance of monetary policy that*

[20] U.S. Bureau of Labor Statistics, "Consumer Price Index Historical Tables for U.S. City Averages, Consumer Price Index for All Urban Consumers (CPI-U)," accessed January 20, 2024, https://www.bls.gov/regions/mid-atlantic/data/consumerpriceindexhistorical_us_table.htm. I note that CPI in January 2024 was 3.1% (*Ibid*)

[21] Federal Reserve Bank of Richmond, "The Fed is Shrinking Its Balance Sheet. What Does That Mean?" January 20, 2024, https://www.richmondfed.org/publications/research/econ_focus/2022/q3_federal_reserve

[22] U.S. Bureau of Labor Statistics and FRED. Figure shows upper-end of Federal Funds Rate range.

[23] *Ibid*.

> *is sufficiently restrictive to bring inflation sustainably down to 2 percent over time and to keep policy restrictive until we're confident that inflation is on a path to that objective.*[24]

That is to say, current inflation levels still remain well above the Federal Reserve's target of 2.0% over the long-term and future developments in inflation and monetary policy remains uncertain.

Despite the recent slowdown to the increase of the Federal Funds Rate, long-term government bond yields increased through most of 2023, with the yield on 10-year U.S. Government Bonds reaching a high of 4.98% in October 2023.[25] Bond yields declined recently as the Federal Reserve signals that the policy rate may be near its peak, and it may cut interest rates depending on future developments in inflation.[26]

Over the same time, other factors have contributed to heightened uncertainty in economic and financial conditions. Geopolitical conflicts in Europe and the Middle East have the potential to impact economic policy, world markets, and energy markets.[27] Heightened geopolitical conflicts may cause investors to change their risk tolerances and the return required to hold assets that are not risk-free.

Finally, I note that systematic risk of utilities (as measured by beta) has held constant. Broader markets of risks, such as forward-looking estimates of the market risk premium have

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24 Board of Governors of the Federal Reserve, "Chair Powell's Press Conference," December 13, 2023, https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20231213.pdf I note that Chair Powell made similar remarks following the January 2024 FOMC meeting. See Board of Governors of the Federal Reserve, "Chair Powell's Press Conference," January 31, 2024, https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20240131.pdf

25 FRED, "Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity," DGS10, accessed January 20, 2024, https://fred.stlouisfed.org/series/DGS10

26 *Supra* n. 24 (Dec 2023 FOMC Press Conference).

27 I acknowledge that there are many non-economic aspects of these conflicts. However, I only focus on the aspects of these conflicts that may affect the cost of equity for utilities, such as PGE.

increased recently. Taken together, several key capital market factors (as well as utility specific risk measures) indicate that the cost of equity is higher today than in the recent past.

Q. What are the expectations for near-term developments in capital market conditions?

A. While future developments in capital market conditions are uncertain, investors continue to remain focused on inflation levels and monetary policy developments. Economists are becoming increasingly optimistic that the Federal Reserve will achieve a "soft landing"—that is, reducing inflation to the Federal Reserve 2% target without the economy entering a recession.[28] However, inflation held steady at approximately 3.0%, which has called into question the timing and extent of future rate cuts. The most recent economic projection materials from the Federal Reserve indicate that the Federal Funds rate will average 4.6% in 2024 and 3.6% in 2025.[29] Whereas, economics and financial professionals surveyed by *Blue Chip Economic Indicators* (BCEI) indicate that the Federal Funds Rate will decline by 111 basis points in 2024.[30] The most recent survey of BCEI respondents indicate that the first cut may not occur until May 2024.[31] At the same time, other economist expect that the rate cuts will not occur for some time and will be smaller.[32] Further, several senior Federal Reserve officials have indicated that the Federal Funds Rate may need to stay high for longer to fight inflation.[33] That is to say, the pace and extent of changes in monetary policy is uncertain and will depend upon future developments in inflation and other economic indicators. At the same time, other factors contributing to economic and financial uncertainty, such as geopolitical tensions, are likely to persist.

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28 Wolters Kluwer, Blue Chip Economic Indicators, Vol. 49 No. 1, January 10, 2024, p. 1.
29 *Supra* n. 24 (Dec 2023 FOMC Press Conference).
30 Wolters Kluwer, Blue Chip Economic Indicators, Vol. 49 No. 1, January 10, 2024, p. 1.
31 Wolters Kluwer, Blue Chip Economic Indicators, Vol. 49 No. 2, February 9, 2024, p. 1.
32 *Ibid*.
33 Value Line, "The View," January 8, 2024.

4. Interest Rates

Q. How do interest rates affect the cost of equity?

A. The current expectations for interest rates affects the cost of equity estimation in several ways. Most directly, the CAPM takes as one of its inputs a measure of the risk-free rate (see Figure 2). All else equal, the estimated cost of equity using the CAPM decreases (increases) by one percentage point when the risk-free rate decreases (increases) by one percentage point. Therefore, to the extent that prevailing government yields are affected by monetary policy and rising geopolitical tensions, using *current* yields as the risk-free rate would affect the CAPM estimate in a manner that may not reflect the forward-looking cost of equity. The allowed fair return on equity for PGE should reflect the future interest rate environment, specifically the environment at the time the rates set in this proceeding will be in effect.

Q. What are the relevant developments regarding interest rates?

A. Yields on 10-year U.S. Treasury Bonds were 4.88% at the time PGE's current ROE was authorized by the Commission on October 30, 2023 and are currently about 100 basis points lower at 3.88%. [34] However, even with this recent decline, yields remain elevated compared to recent historical levels (see Figure 4 below).

Looking forward, financial analysts as well as government agencies expect Treasury bond yields to remain relatively constant in the near-term and then decrease over the next couple of years. However, they do not expect the yields to return to the low levels of the recent past. Consensus estimates from BCEI forecast that the yield on 10-year Treasury bonds will average 3.9% in 2024, 3.7% in 2025, and then 3.5% in 2026.[35] The Congressional Budget

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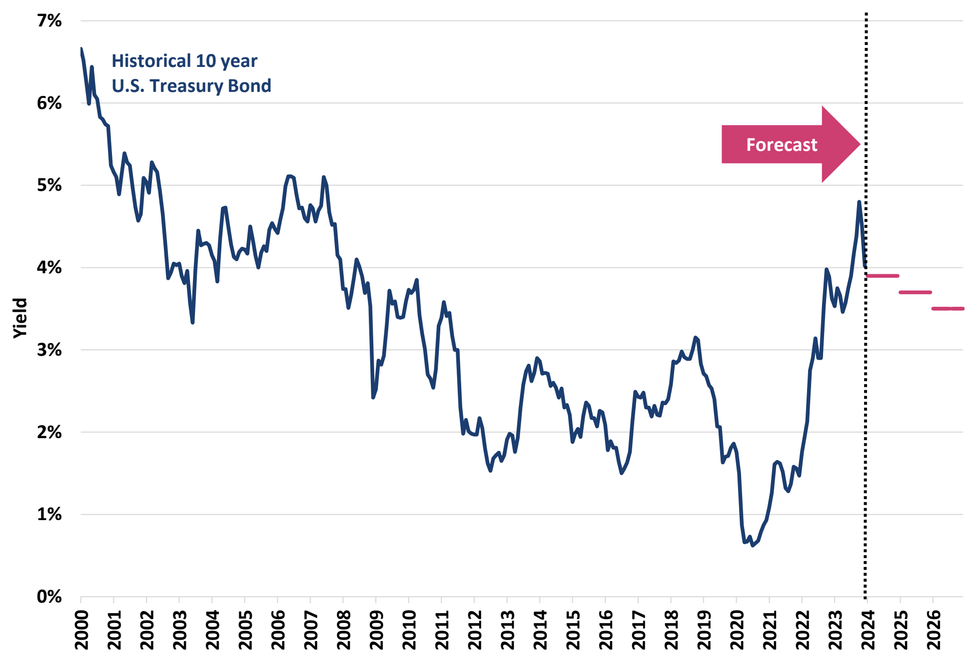
[34] FRED, "Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity, Quoted on an Investment Basis," DSG10, as of October 30, 2023, accessed January 17, 2024, https://fred.stlouisfed.org/series/DGS10

[35] Wolters Kluwer, Blue Chip Economic Indicators, January 10, 2024, pp. 2-3 and October 10, 2023, pp. 2-3, 14.

Office (CBO) forecast that the yield on 10-Year Treasury bonds will be 4.8% at the end of 2024 and 4.3% at the end of 2025.[36]

Figure 4
Historical and Projected 10-Year Treasury Bond Yields[37]



5. Risk Premiums

Q. How do risk premiums affect the cost of equity?

A. Risk premiums provide an indication of the compensation investors expect to hold securities that are not risk-free. If an investor demands a larger risk premium, then the cost of equity will be larger. There are several indicators of risk premiums in addition to the yield spreads discussed above. For example, indicators such as stock market volatility (*e.g.*, VIX) provide insights into the risk premium required by investors in the coming 30 days. SKEW measures the market's willingness to pay for protection against negative substantial stock market events

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36 Congressional Budget Office, "CBO's Current View of the Economy from 2023 to 2025," December 2023, https://www.cbo.gov/system/files/2023-12/59837-Economy.pdf

37 Bloomberg (historic data) and Wolters Kluwer, Blue Chip Economic Indicators, October 2023 and January 2024 (forecast data)

and provides a useful indicator of volatility over the next 12 months. Whereas the MRP measures the compensation required to hold a security over a long investment horizon, such as the period when rates set in this proceeding will be in effect. For this reason, the forecast MRP needs to be taken into consideration when determining the cost of equity in this proceeding.

Q. What are the current measures of market volatility and investors' risk perception?

A. Measures of market volatility are slightly below long-term averages. The Chicago Board of Option Exchange's volatility index (VIX) is currently around 15.3, which is in-line with the long-run average of 19.6.[38] However, the SKEW index is currently 147.8.[39] above the long-run historic average of 121.3.[40] At the same time, investors are facing on-going geopolitical tension, tight monetary policy, and fiscal stimulus,[41] consequently, the evidence regarding investors' risk perception is mixed.

Q. What is the Market Risk Premium?

A. In general, a risk premium is the amount of "excess" return—above the risk-free rate of return—that investors require to compensate them for taking on risk. As illustrated in Figure 2, the riskier the investment, the larger the risk premium investors will require. The market risk premium is the risk premium associated with investing in the market as a whole. Since the so-called "market portfolio" embodies the maximum possible degree of diversification for

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38 Cboe, VIX, accessed January 17, 2024, https://www.cboe.com/tradable_products/vix/

39 Cboe, SKEW, accessed January 17, 2024, https://www.cboe.com/me/indices/dashboard/skew/

40 *Ibid*. Long-term average calculated from January 2, 1990 to December 31, 2023. A SKEW value of 100 indicates outlier returns are unlikely, but as the SKEW increases, the probability of outlier returns becomes more significant.

41 For example, the Inflation Reduction Act, H.R. 5376, https://www.congress.gov/117/bills/hr5376/BILLS-117hr5376enr.pdf

investors,[42] the MRP is a highly relevant benchmark indicating the level of risk compensation demanded by capital market participants. It is also a direct input necessary to estimating the cost of equity using the CAPM and other risk-positioning models.

Q. What are the current estimates of the MRP?

A. Bloomberg's forward-looking MRP has increased in recent months to 6.87% as of the end of 2023, when measured relative to a 10-year U.S. Treasury Bond yield.[43] By comparison, the MRP was 133 basis points lower at 5.54% in September 2022 when the yield on 10-year U.S. Treasures was 3.83%—approximately equal to the yield at the end of 2023. At the same time, Bloomberg's expected market return increased from 9.36% in September 2022 to 10.75% in December 2023.[44] Using the FERC methodology, forecasted MRP is 7.87% using growth rates from *IBES* and 7.90% using growth rates from *Value Line*.[45] By comparison, *Kroll's* historic MRP for the period 1926 through 2022 is 7.17%.[46] Thus, most of the evidence indicates that the MRP is approximately 7%.

Q. What does the yield curve indicate about the risk premium demanded by investors?

A. The yield curve, which displays the current yield on bonds by maturity, has an inverted shape, so that the yield on bonds with shorter maturities are higher than the yield on bonds with longer maturities (see Figure 5). This is unusual and is often considered a risk to equity investors as such phenomenon has been associated with a coming downturn in the market.[47]

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42 In finance theory, the "market portfolio" describes a value-weighted combination of all risky investment assets (e.g., stocks, bonds, real estate) that can be purchased in markets. In practice, academics and financial analysts nearly always use a broad-based stock market index, such as the S&P 500, to represent the overall market.

43 Bloomberg as of December 31, 2023.

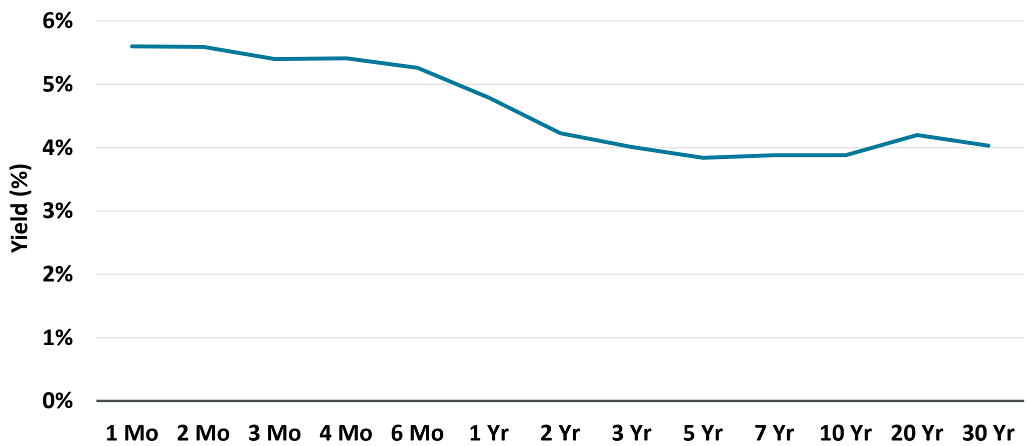
44 *Ibid*.

45 See PGE Exhibit 605C. As of December 31, 2023. The FERC methodology is based on 30-year US Treasury bonds. The FERC MRP calculated using 20-year US Treasury bonds is 7.69%.

46 Kroll, U.S. Cost of Capital Navigator value as of December 31, 2022, accessed January 8, 2024.

47 Federal Reserve Bank of New York, "The Yield Curve as a Leading Indicator," https://www.newyorkfed.org/research/capital_markets/ycfaq.html#/

Figure 5
U.S. Treasury Yield Curve[48]



Q. Please summarize how economic developments affected the return on equity and debt that investors require.

A. Utilities rely on investors in capital markets to provide funding to support their capital expenditure programs as well as their efficient business operations. Investors consider the risk-return tradeoff in choosing how to allocate their capital amongst different investment opportunities. It is therefore important to consider how investors view current economic and financial conditions, including plausible developments in interest rates, inflation, and other key indicators.

Economic and financial conditions have changed substantially in the past year or so following the rapid increase in inflation, the monetary policy response by the Federal Reserve, and ongoing geopolitical tensions in Europe and the Middle East. Inflation has decreased from recent levels but remains above the Federal Reserve's target level. The Federal Reserve is signaling that it may cut the Federal Funds rate as soon as this year, but the timing and extent

48 U.S. Department of Treasury, "Daily Treasury Par Yield Curve Rates," as of December 31, 2023, https://home.treasury.gov/resource-center/data-chart-center/interest-rates/TextView?type=daily_treasury_yield_curve&field_tdr_date_value_month=202402.

of cuts is not known. Forecasted interest rates remain near current levels, albeit slightly lower through 2025. At the same time, indicators of risk premiums required by investors is currently higher than historic levels. Taken together, there are reasons to believe that the return expectations of investors reflect the ongoing uncertainty related to economic and financial conditions.

<u>6. Estimating the Cost of Equity</u>

Q. Please describe your approach to determine the cost of equity for PGE.

A. The approach to estimating the cost of equity for PGE focuses on measuring the expected returns required by investors to invest in companies that face business and financial risks comparable to those faced by PGE. The proxy group consists of publicly traded, vertically integrated electric utilities. I consider the results from the proxy sample when deriving estimates of the representative cost of equity using standard financial models, including the Capital Asset Pricing Model ("CAPM") and two versions of the Discounted Cash Flow ("DCF") model.

I also perform an analysis of historic allowed ROEs for vertically integrated electric utilities in relation to prevailing risk-free interest rates at the time the ROE was authorized and use the implied allowed risk-premium relationship to estimate a utility cost of equity consistent with current economic conditions. The results of this implied risk premium analysis (sometimes referred to herein as the "Risk Premium" model) are an additional consideration that supports my recommendation and serves as a check on the reasonableness of my market-based results.

7. Proxy Group Selection

Q. How did you identify proxy companies of comparable risk to PGE?

A. PGE is a regulated utility engaged in generation, transmission, and distribution operations to serve its customers. The business risks associated with these activities depend on many factors, including specific characteristics of the regulatory environment and PGE's service territory. It is therefore not possible to identify publicly traded proxy companies (*i.e.*, companies whose shares are traded on a stock exchange) that replicate every aspect of PGE's business risk profile. However, selecting publicly traded companies with business operations concentrated in regulated industries, whose primary line of business are in electric generation, transmission, and distribution s and/or business environments is an appropriate starting point for selecting one or more groups of proxy companies with comparable risks to PGE.

Q. Can you summarize how you selected the Electric Utility sample?

A. I formed the proxy sample by starting with a universe of publicly traded electric utilities, as classified by *Value Line Investment Analyzer* (*Value Line*). This resulted in an initial group of 38 companies. I then eliminated companies from the initial group by applying additional screening criteria designed to remove companies with unique circumstances that may bias the cost of capital estimates. Specifically, I required the proxy companies to have the following:

- A significant portion of the proxy company's business operations is concentrated in regulated utility activity.[49]

[49] I rely on the designations reported by the Edison Electric Institute (EEI) in their 2022 Financial Review, https://www.eei.org/en/issues-and-policy/finance-and-tax.

- No significant merger and acquisition ("M&A") during the relevant estimation window.[50]
- No recent dividend cuts or other significant events that could cause growth rates or beta estimates to be biased.[51]
- Market capitalization of at least $300 million for liquidity purposes.
- The necessary market data available for estimation.

In addition to my standard set of screening criteria, I also eliminated companies that do not engage in vertically integrated electric utility services. Applying these selection criteria results in a final proxy sample comprised of 27 electric utilities as shown in Figure 6.

[50] I look 5 years back for pending M&A transactions and 6 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 its business and financial risk characteristics.

[51] Specifically, I look for dividend cuts that occurred in the 6 months prior to the estimation date of my analysis.

Figure 6
Electric Sample

Company	Annual Revenue (Q3 2023) ($MM) [1]	Regulated Assets [2]	Market Cap. (Q4 2023) ($MM) [3]	Value Line Beta [4]	S&P Credit Rating [5]	Long-Term Growth Estimate [6]
ALLETE	$1,903	MR	$3,509	0.95	BBB	5.8%
Alliant Energy	$4,124	R	$13,077	0.90	A-	6.9%
Amer. Elec. Power	$19,286	R	$42,680	0.80	A-	5.2%
Ameren Corp.	$7,928	R	$19,455	0.90	BBB+	5.6%
Avista Corp.	$1,744	R	$2,744	0.95	BBB	5.9%
Black Hills	$2,531	R	$3,700	1.00	BBB+	4.7%
CMS Energy Corp.	$7,790	R	$16,914	0.85	BBB+	6.9%
CenterPoint Energy	$9,225	R	$18,194	1.15	BBB+	5.0%
DTE Energy	$13,827	R	$22,745	1.00	BBB	6.6%
Duke Energy	$29,199	R	$74,426	0.90	BBB+	6.4%
Edison Int'l	$16,648	R	$26,793	1.00	BBB	5.1%
Entergy Corp.	$12,695	R	$21,439	0.95	BBB+	0.9%
Evergy Inc.	$5,600	R	$11,915	0.95	BBB+	5.1%
Exelon Corp.	$21,042	R	$36,500	n/a	BBB+	9.0%
IDACORP Inc.	$1,777	R	$4,978	0.85	BBB	4.3%
MGE Energy	$715	R	$2,620	0.75	AA-	4.5%
NextEra Energy	$27,401	MR	$124,492	1.00	A-	8.2%
NorthWestern Corp.	$1,491	R	$3,151	0.95	BBB	4.2%
OGE Energy	$2,820	R	$7,074	1.05	BBB+	11.3%
Otter Tail Corp.	$1,336	R	$3,428	0.95	BBB	-13.1%
PPL Corp.	$8,571	R	$19,723	1.10	A-	7.9%
Pinnacle West Capital	$4,714	R	$8,270	0.95	BBB+	6.6%
Public Serv. Enterprise	$2,885	R	$30,750	0.95	BBB+	5.4%
Sempra Energy	$11,771	R	$23,414	1.00	BBB+	7.5%
Southern Co.	$16,684	R	$77,031	0.95	BBB+	7.9%
WEC Energy Group	$26,255	R	$26,358	0.85	A-	5.8%
Xcel Energy Inc.	$9,234	R	$34,132	0.85	A-	6.2%
Electric Sample	**$9,970**		**$25,167**	**0.94**	**BBB+**	**5.4%**

Sources and Notes:
[1]: Bloomberg as of December 31, 2023.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. JF-3 Panels A through I.
[4]: See Schedule No. JF-10
[5]: Bloomberg as of December 31, 2023.
[6]: See Schedule No. JF-5.

Q. How do the proxy companies' financial metrics compare to those of PGE?

A. PGE's annual revenues from the prior four quarters was $2,885 million, which is smaller than the revenue generated by the average electric proxy company of $9,970 million over the same time period. PGE has a BBB+ rating from S&P Global Ratings[52] and an A3 rating from Moody's.[53] This is consistent with the average credit rating of the Electric Sample (BBB+).[54] PGE has a *Value Line* beta of 0.9 versus the sample average of 0.94. Finally, PGE's growth rate estimate is 5.4%, which is the same as the sample average.

<u>8. Capital Structure</u>

Q. What regulatory capital structure did you use in your ROE analysis?

A. In my ROE analysis, I used PGE's requested capital structure consisting of 50.0% equity and 50.0% debt.

<u>9. The CAPM Based Estimates</u>

Q. Please briefly explain the CAPM and ECAPM.

A. The CAPM assumes the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market. The CAPM posits a risk-return relationship known as the Security Market Line (see Figure 2), in which the required expected return on an asset (above the risk-free return) is proportional to that asset's relative risk as measured by that asset's beta. More precisely, the CAPM states that the cost of capital for an investment (*e.g.*, a particular common stock), is determined by the risk-free rate plus the stock's systematic risk (as measured by beta) multiplied by the MRP.

In addition to the CAPM, I use the Empirical Capital Asset Pricing Model, or "ECAPM." Empirical research has long shown that the CAPM tends to overstate the actual sensitivity of

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52 S&P Global Ratings, "Portland General Electric Co." December 14, 2023.

53 "Portland General Electric Company: Update to Credit Analysis." Moody's 18 April 2023.

54 Of note, credit ratings measure default risk and the current probability of default for both A and BBB rated utilities is zero. Source: S&P Global Ratings, "Default, Transition, and Recovery: 2022 Annual U.S. Corporate Default and Rating Transition Study," June 13, 2023.

the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted.[55] The ECAPM adjusts the risk-return line in the CAPM by a factor of $\boldsymbol{\alpha}$ to account for these empirical findings. I further discuss the CAPM and ECAPM in the Technical Appendix to my Direct Testimony.[56]

10. CAPM/ ECAPM Inputs

Q. What value did you use for the risk-free rate of interest?

A. I rely on the long-term U.S. Treasury Bond interest rates as the risk-free rate in my analysis.[57] To obtain a risk-free rate, I start with the most-recent forecast for 10-year U.S. Treasury Bond yields published by *Blue Chip Economic Indicator*s. Recognizing the fact that the cost of capital is a forward-looking concept and that the rates set forth in this proceeding will be in effect starting in 2025, I rely on *BCEI*'s forecasted yield on 10-year U.S. Treasury Bonds in 2025, which is 3.7%.[58] I then adjust this upwards by 50 basis points, which reflects my estimate of the historic maturity premium of the 20-year U.S. Treasury Bond yield over the 10-year U.S. Treasury Bond yield. [59] This gives me a risk-free rate of 4.2%.

Q. What value did you use for the market risk premium?

A. Like the cost of capital itself, the MRP is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can expect to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly

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55 *See* Figure B-3 in PGE Exhibit 604 for references to relevant academic articles.

56 *See* PGE Exhibit 604.

57 Specifically, I rely on the 20-year U.S. Treasury Bond yield for the risk-free rate. The use of a 20-year government bond is consistent with the measurement of the historic Ibbotson MRP and permits me to use a series that has been in consistent circulation since the 1990's (the 30-year government bond was not issued from 2002 to 2006).

58 Wolters Kluwer, Blue Chip Economic Indicators, Vol. 49 No. 1, January 10, 2024, p. 3.

59 This maturity premium is estimated by comparing the average excess yield on 20-year versus 10-year Government Bonds over the period 1990-2023, using data from Bloomberg.

observable. Rather, it must be inferred or forecasted based on known market information. Therefore, I rely on scenarios that utilize different market information to estimate the MRP.

In the first instance, I use the long-term historical average premium of market returns over the income returns on government bonds.[60] The average market risk premium from 1926 to the present (December 2022) is 7.17%, as reported by Kroll.[61] I also use Bloomberg's forward-looking MRP estimate of 6.37%, as of December 31, 2023.[62] I note that this is a conservative estimate as the FERC-relied upon methodology to determine the MRP currently results in an MRP of 7.87%.[63]

Q. What estimates of beta did you use in your analysis?

A. I used *Value Line* betas, which are estimated using five years of weekly historical return data and are Blume adjusted.[64] Importantly, these betas—which are measured (by *Value Line*) using the market stock return data of the proxy companies—reflect the level of financial risk inherent in the proxy companies' market value leverage ratios over the estimation period. Because PGE's regulatory capital structure includes a substantially higher proportion of debt financing than the market capital structure of the proxy companies,[65] the financial risk associated with an equity investment in PGE's rate base is correspondingly greater than the financial risk borne by investors in the proxy companies' publicly traded stock. Importantly, both the DCF model and the CAPM-based models use market data to estimate the ROE, so it

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[60] The longest period for which Kroll reports data is 1926 to current. Based on financial textbooks such as Ross, Westerfield and Jaffe, "*Corporate Finance*," 10th Edition, 2013, pp. 324-327, I use the longest period for which reliable estimates are available – in this case 1926 to 2022.

[61] Kroll Cost of Capital Navigator, U.S. Cost of Capital Module, accessed December 31, 2023, value as of December 31, 2022.

[62] PGE Exhibit 605C, measured relative to a 20-year US Treasury bond.

[63] *Ibid.* The FERC methodology is based on 30-year US Treasury bonds. The FERC MRP calculated using 20-year US Treasury bonds is 7.69%.

[64] See Value Line Glossary, accessible at http://www.valueline.com/Glossary/Glossary.aspx

[65] The average market capital structure of the Electric Sample is 42% debt. See PGE Exhibit 605C.

is the market value capital structure that is the relevant comparison across companies.[66] Consequently, I apply standard textbook techniques to unlever the *Value Line* betas for each of the proxy companies and then relever the resulting asset betas at PGE's requested 50.0% regulatory capital structure.[67]

Q. Please summarize the parameters of the two scenarios you considered in your CAPM and ECAPM analyses?

A. The parameters for the two scenarios I consider are shown in Figure 7 below. In Scenario 1, I use Kroll's historic MRP of 7.17% with my estimate of the forecasted risk-free rate of 4.2%. In Scenario 2, I use Bloomberg's forward-looking MRP of 6.37% with the same risk-free rate of 4.2%.

Figure 7
CAPM and ECAPM Scenarios

	Scenario 1	Scenario 2
Risk-Free Interest Rate	4.20%	4.20%
Market Risk Premium	7.17%	6.37%

11. Results of the CAPM Based Models

Q. What are the results from your CAPM and ECAPM analyses?

A. Figure 8 below shows the results of the CAPM and ECAPM analysis for the Electric Sample at PGE's requested capital structure of 50% equity. These estimates reflect the financial risk

66 As the Risk Premium Model's ROE estimates are based on book value capital structures, the relevant comparison is across book value capital structures for that model.

67 The Technical Appendix (PGE Exhibit 704) to my testimony provides a detailed description of the standard textbook formulas used to implement the "Hamada" technique for unlevering measured equity betas based on the proxy companies' capital structures to calculate "asset betas" that measure the proxy companies' business risk independent of the financial risk impact of differing capital structures. The proxy group average asset betas are then relevered at the target capital structure (*i.e.*, PGE's regulatory capital structure), with the precise relevered beta depending on the specific version of the unlevering/ relevering formula employed.

adjustments based on the differences in the average market-value capital structure of the proxy companies and PGE's requested capital structure.

Figure 8
CAPM and ECAPM Summary at 50% Equity Capital Structure

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Electric Sample		
Financial Risk Adjusted Method		
CAPM	12.0%	11.2%
ECAPM (α = 1.5%)	12.1%	11.3%
Hamada Adjustment Without Taxes		
CAPM	11.8%	11.0%
ECAPM (α = 1.5%)	11.7%	10.9%
Hamada Adjustment With Taxes		
CAPM	11.7%	10.8%
ECAPM (α = 1.5%)	11.6%	10.8%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 4.20%, Long-Term Market Risk Premium of 7.17%.
[2]: Long-Term Risk Free Rate of 4.20%, Long-Term Market Risk Premium of 6.37%.

Q. How do you interpret the results of your CAPM and ECAPM analyses?

A. The ROE estimates from the CAPM and ECAPM range from 10.8% to 12.1%. Of the results, I place less weight on the CAPM estimates because this method does not adjust for the empirical findings that the return on equity is less sensitive to beta than predicted by CAPM; therefore, I give the most weight to the ECAPM results which does adjust for these empirical findings. However, I note that there is currently little difference between the results from the CAPM and ECAPM due to current beta levels. I also place more weight on results derived using Hamada to adjust for financial leverage. Therefore, I find a reasonable range for the Electric sample to be 11.00% to 11.5%.[68]

[68] To derive a reasonable range, I use results from the Hamada-adjusted ECAPM and then exclude the highest and lowest results, then round the resulting range to the nearest 0.25%.

12. The DCF Based Estimates

Q. Please describe your DCF model's approach to estimating the cost of equity.

A. The DCF model attempts to estimate the cost of capital for a given company directly, rather than based on its risk relative to the market as the CAPM does. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream. One version of the DCF, which I refer to as the single-stage DCF model, says the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends.

In addition, I also rely on a multi-stage DCF model, which assumes earnings and dividends can grow at different rates but must grow at the same rate in the final, constant growth rate period.[69] In my implementation of the multi-stage DCF, I assume that companies grow their dividend for five years at the forecasted company-specific rate of earnings growth, with that growth then tapering over the next five years toward the growth rate of the overall economy (*i.e.*, the long-term gross domestic product (GDP) growth rate forecasted to be in effect ten years or more into the future). I further discuss the single- and multi-stage DCF in the Technical Appendix to my Direct Testimony.[70]

13. DCF Inputs

Q. What growth rate information do you use?

A. The first step in my DCF analysis (either single- or multi-stage formulations) is to examine a sample of investment analysts' forecasted earnings growth rates for companies in my proxy

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69 The Surface Transportation Board uses a cash flow-based model with three stages. See, for example, Surface Transportation Board Decision, "STB Ex Parte No. 664 (Sub-No. 1)," Decided January 23, 2009.

70 PGE Exhibit 604.

group. Specifically, I use investment analysts' forecasts earnings growth rates for each of the proxy companies, sourced from *Value Line* and Thomson Reuters *IBES*.[71] The single-stage DCF models require forecast growth rates that reflect investor expectations about the pattern of dividend growth for the companies over a sufficiently long horizon, but estimates are typically only available for 3-5 years.

I rely on the same growth rates in multi-stage DCF, however, I taper these growth rates toward a stable growth rate corresponding to a forecast of long-term GDP growth for all companies. In the final, constant-growth stage of the multi-stage DCF analysis, I use the most recent long-term U.S. GDP growth forecast from Blue Chip Economic Indicators of 4.0%.[72]

Additionally, I estimate the dividend yield of the proxy companies using the most recently available dividend information and the average of the last 15 days of stock prices ending December 31, 2023.

14. Results from the DCF Models

Q. Please summarize the DCF-based cost of equity estimates for the proxy group.

A. Figure 9 below shows the results of DCF model analysis for the Electric Sample at PGE's requested capital structure of 50% equity. These estimates reflect the financial risk adjustments based on the differences in the average market-value capital structure of the proxy companies and PGE's requested capital structure.

[71] Short-term (5 year) EPS growth rates as of December 31, 2023. I develop a weighted average growth rate weighted by the number of analysts and counting Value Line as one analyst.

[72] Blue Chip Economic Indicators, October 2023, p. 14.

Figure 9
DCF Model Results at 50% Equity Capital Structure

	Single-stage [1]	Multi-stage [2]
Electric Sample	11.3%	9.4%

Q. How do you interpret the results of your DCF analyses?

A. The DCF results for the Electric Sample range from 9.4% for the multi-stage DCF to 11.3% for the single-stage DCF. Based on this, I find a reasonable range of 9.5% to 11.25%.[73]

15. Risk Premium Model

Q. Please explain the Risk Premium Model.

A. The Risk Premium Model estimates the cost of equity capital for utilities based on the historical relationship between allowed ROEs in utility rate cases and the risk-free rate of interest prevailing at the time the ROEs were granted. This relationship is described in the equation below, where the "risk premium" implied by this relationship is added to the prevailing risk-free interest rate:

$$Cost\ of\ Equity = r_f + Risk\ Premium$$

Q. What are the merits of this approach?

A. First, it 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. Second, the allowed returns are readily observable to market participants, who will use this one data input in making investment decisions, so that the information is, at the very least, a good check on whether the return is comparable to that of other investments. Third, I analyze the spread between the

[73] To derive my reasonable ranges, I look to the range of results from the single-stage and multi-stage DCF models and then round the range to the nearest 0.25%.

allowed ROE at a given time and the then-prevailing interest rate so that I properly consider the interest rate regime at the time the ROE was awarded. This implementation allows me to compare allowed ROE granted at different times and under different interest rate regimes.

Q. How did you perform your Risk Premium analysis?

A. To perform the Risk Premium analysis, I rely on vertically integrated electric utility rate case from 1990 through Q4 2023, as reported by S&P's Regulatory Research Associates.[74] I also used the average 20-year U.S. Treasury Bond yield that prevailed in each quarter during the analysis period. I then compared (statistically) the average allowed rate of return on equity granted by U.S. state regulatory agencies in electric utility rate cases to the prevailing yield on the U.S. Treasury bonds in each quarter.[75] I calculated the allowed utility "risk premium" as the difference between allowed returns and the Treasury bond yield in each quarter, since this represents the compensation for risk allowed by regulators. Then, I used ordinary least squares ("OLS") regression to estimate the parameters of the linear equation:

$$Risk\ Premium\ =\ A_0\ +\ A_1\ \times\ (Treasury\ Bond\ Yield)$$

<u>16. Results from the Risk Premium Model</u>

Q. What are the results from your Risk Premium analysis?

A. The results from my linear regression are shown in Figure 10.[76] The A_0 parameter (intercept) estimate is 8.64% and the A_1 parameter (slope) is -0.563. The negative slope reflects that regulators grant smaller premiums when U.S. Treasury Bond yields are higher. This is consistent with empirical observations that the premium investors require to hold equity rather

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74 S&P Market Intelligence, as of December 2023.

75 I rely on the 20-year government bond to be consistent with the analysis using the CAPM to avoid confusion about the risk-free rate. While it is important to use a long-term risk-free rate to match the long-lived nature of the assets, the exact maturity is a matter of choice.

76 PGE Exhibit 605C.

than government bonds increases as U.S. Treasury Bond yields decline. Finally, I note that the results show that the Risk Premium model fits the data well with an R-square of 0.856. R-squared is a measure of how well the data fits the model—an R-squared above 0.8 indicates a solid result.

Figure 10
Implied Risk Premium Model Estimates: Vertically Integrated Electric Utilities

Risk Premium = A_0 + (A_1 x Treasury Bond Rate)

R Squared	0.856
Estimate of Intercept (A_0)	8.64%
Estimate of Slope (A_1)	-0.563

Predicted Risk Premium		**Exp. Treasury Bond Rate**		**Est. Cost of Equity for Vertically Integrated Electric Utilities**
6.27%	+	4.20%	=	10.5%

Sources and Notes:
[1]: Authorized ROE Data from S&P Market Intelligence as of 12/31/2023.
[2]: January 2024 Blue Chip Economic Indicators 2025 yield projections 10 year T-bill yield + maturity premium between 10 year and 20 year U.S. Government bonds.
See Regression Results for derivation of regression coefficients A_0 and A_1

Q. How do you interpret the results of your Risk Premium analysis?

A. The results in Figure 10 indicate an ROE of 10.5% for an average vertically integrated electric utility, based on the risk premium model, which is consistent with the results from the CAPM and DCF models. Unlike the CAPM and DCF models, the Risk Premium model is based on historical allowed returns and not underpinned by fundamental financial principles. However, I believe that this analysis, when properly designed, executed, and placed in the proper context, is a valid and useful approach to estimating utility ROEs. Because it relies on the returns for regulated utilities, I believe this method provides a good way to assess directly whether the ROE is commensurate with that available to alternative regulated investments of similar risk.

17. Summary of ROE Estimates

Q. Please summarize your results before considering where to place PGE within the range of ROE estimates.

A. Figure 11 below summarizes the reasonable range of ROE results from the CAPM, DCF, and Risk Premium models for the Electric Sample. The CAPM and DCF results are based on PGE's requested 50% equity capital structure.

Figure 11
Summary of Reasonable Rages at 50% Equity

	Electric Sample
CAPM/ ECAPM	11.0% to 11.5%
DCF	9.5% to 11.25%
Risk Premium	10.5%

18. Business Risk Considerations

Q. How does PGE's regulatory environment compare to that of the other proxy companies?

A. PGE is regulated by the Oregon Public Utility Commission, which S&P's Regulatory Research Associates ranks as "Average/2," indicating a balanced risk level from an investor's perspective.[77] Like the electric utility proxy companies, PGE has several alternative regulatory mechanisms.[78] The Company has a Power Cost Adjustment Mechanism ("PCAM") as do almost all of the proxy companies, however, PGE's PCAM introduced an asymmetrical cost sharing arrangement that is not common in other utilities' mechanisms.

On the other hand, 20 proxy companies have full or partial decoupling mechanisms. In PGE's last general rate case, the Commission authorized PGE to file to reinstate its

77 S&P Capital IQ, "Regulatory Research Associates: Oregon Public Utility Commission," accessed January 20, 2024. Note, there are three rating categories, Above Average, Average, and Below Average. Within each category, RRA assigns a number (1 to 3) indicating a relative position within the rating category.

78 S&P Capital IQ, "Adjustment Clauses: A state by state overview," July 2022.

decoupling mechanism,[79] which I understand is on-going and the decoupling mechanism has not been implemented. Sixteen proxy companies have forward test years, similar to PGE. Finally, 14 proxy companies also have some form of a delivery infrastructure rider.[80]

Q. Please discuss PGE's Power Cost Adjustment Mechanism and how it affects the Company's business risk relative to the sample.

A. The PCAM allows PGE to recover the cost of wholesale power that it supplies to its customers based on the actual total power costs less certain costs incurred during Reliability Contingency Events (RCEs). As of January 2024, PGE can recover 80% of costs prudently incurred during RCEs, where RCE is defined by three criteria, however the RCE only partially addresses some of the power cost risk and is effective through 2025. Most notably, PGE has an asymmetrical deadband where PGE absorbs $30 million of excess power costs before sharing with customers, whereas, PGE can only retain $15 million of power cost savings before refunding customers.

The PCAM is also subject to an earning test based on 100 basis points above or below its allowed ROE of 9.5%. This creates additional risks for PGE to earn its allowed ROE if power costs are higher than forecasted because it must first absorb $30 million of excess power costs before sharing 90% of costs with customers up to an earned ROE 100 basis points below its current allowed ROE (*i.e.*, 8.5%) before a customer surcharge occurs.[81]

All else equal, the structure of the PCAM increases the risk of PGE relative to the proxy company. According to S&P's Regulatory Research Associates, the majority of electric

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79 Docket No. UE 416, Order No. 23-386 (October 30, 2023)at 13.
80 PGE Exhibit 605C.
81 *Ibid*. Note, PGE's ROE will not exceed 8.5% if a surcharge occurs.

utilities do not share power costs over or under recovery with customers.[82] Further, in a recent credit ratings report, Moody's noted "unrecoverable power costs via asymmetric customer sharing of actual costs" as a credit challenge for PGE.[83]

Q. How have recent energy and climate policies impacted the business risks of PGE's electric utility operations?

A. Oregon, like many other states, is pursuing aggressive climate and energy policies with the goal of decarbonizing the electric (and natural gas) sector. In June 2021, the Oregon Legislature passed HB 2021, which requires retail electricity providers to reduce GHG emissions from serving retail electricity customers 80% by 2030, 90% by 2035, and 100% by 2040.[84] PGE is making substantial investments to achieve these climate and energy goals. In addition to renewable and non-emitting energy resources, the Company is also making investments to increase the resiliency of its system to mitigate extreme weather and wildfire events.[85]

For PGE, the emphasis on decreasing carbon emissions and transitioning to a carbon-free electric system is directionally positive but also introduces some uncertainty about PGE's future utility operations. Enabling decarbonization will require significant investments by electric utilities, like PGE, to build new clean generation resources and transmit power to end users. PGE expects to spend $5.1 billion over the next five years to fund its capital plan.[86] This directionally increases the risk for utilities, like PGE, with decarbonization goals as the utilities must secure and deploy the required capital and then recover it from customers over

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82 S&P Global, "Adjustment clauses: A state by state overview," July 2022. As noted above, PGE has filed to reinstate its decoupling mechanism, which I understand is not yet in place.

83 "Portland General Electric Company: Update to Credit Analysis." Moody's 18 April 2023.

84 Portland General Electric Co., "2022 Annual Report," p. 42, https://investors.portlandgeneral.com/static-files/18b37e31-ebfd-4cc0-93e7-fb9c8e1c32b3.

85 Portland General Electric, "Investor Presentation," November 10, 2023, p. 5.

86 *Id.*, p. 10.

time.[87] Finally, the transition to clean energy future will likely change how and when customers use electricity. This will require utilities to invest in the electric system and customer-side initiatives (*i.e.*, demand response) to continue to provide safe and reliable service to customers.

Q. What are the wildfire risks faced by PGE and how do the risks compare to the electric utility proxy companies?

The risk of wildfire in the Western U.S. has increased recently. PGE files an annual Wildfire Mitigation Plan pursuant to Oregon Administration Rule 860, identifying plans and investments which helps to mitigate some of this wildfire risk. Outside of Oregon, utilities in other states, such as California, Washington, and Hawaii are making similar investments and developing wildfire mitigation plans in response to the increasing wildfire risks. That is to say, wildfire risk is relatively higher for PGE (and other utilities in the western US) than the majority of the proxy sample that operates in other parts of the country.

Q. How does PGE's size relative to the proxy companies affect the cost of capital?

A. The majority of the proxy companies in the Electric Sample are larger than PGE. For example, PGE has approximately $10.5 billion of total assets, whereas the total assets of the average electric proxy company is $49.8 billion.[88] Empirically, investors have required a higher premium to invest in smaller companies than in larger ones. For example, *Kroll*'s data indicate that PGE's total assets put it in the 10th portfolio (out of 25),[89] while the average electric proxy companies fall in the 3rd portfolio. Empirical evidence suggests that investors in PGE may require a premium over and above that required for larger companies. Kroll's data suggest

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87 See, for example, Brealey, Myers, Allen, "Principles of Corporate Finance," 10th Edition, 2011, pp. 248-249

88 PGE Exhibit 605C.

89 Kroll, "Supplementary Risk Premium Report Study," as of December 31, 2022. Largest companies are in Portfolio 1 whereas the smallest companies are in Portfolio 25.

that a company in the 10th portfolio has a 37 basis points higher average return than a larger company in the 3rd portfolio.[90]

Q. What do you conclude about PGE's business risk relative to the Electric Sample?

A. PGE's business operations are similar to those of the other vertically integrated electric utilities that comprise the Electric Sample. PGE's S&P credit rating of BBB+ is equal to the average credit of the proxy sample. The Company is smaller than the average proxy company in terms of assets, annual revenues, as well as market capitalization. PGE, like the rest of the proxy companies, has access to various alternative regulatory mechanisms, renewable generation riders, environmental compliance riders, and is in the process of reinstating a decoupling mechanism (but currently does not have one in place). However, the Company's Power Cost Adjustment mechanism is unlike similar mechanisms and is higher risk. PGE is also making significant investments to achieve its, and Oregon's, clean energy and climate goals, similar to other utilities operating in states with similar mandates. Finally, unlike most of the companies in the proxy sample, PGE faces increased risk from wildfires in the region. Taken together, I consider PGE to have higher risk than the median risk profile of the proxy companies.

19. Return on Equity Recommendation

Q. Please summarize your conclusion regarding PGE's risk and your recommended ROE.

A. Based on my implementation of standard cost of capital estimation models, I find the model results support a reasonable range of ROE estimates of 10.25% to 11.25% (midpoint 10.75%) at PGE's requested 50.0% equity capital structure. The reasonable range is supported by the results from CAPM/ECAPM and the DCF models using a proxy group of vertically integrated

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[90] *Ibid*.

utility proxy groups. The CAPM/ECAPM results show a reasonable range of 11.0% to 11.5% and the DCF results show a reasonable range of 9.5% to 11.25%. This is further supported by the results of the Risk Premium Model of 10.5% based on allowed ROEs awarded to vertically integrated electric utilities and prevailing government bond yields at the time of the ROE decisions.

I understand that PGE is requesting an allowed ROE of 9.75% on the equity portion of its rate base, which is supported by the reasonable range of ROE results albeit towards the lower end of the DCF results. I find the requested ROE of 9.75% to be conservative given the results of my analysis and my assessment that PGE has higher business risks than that of the proxy companies. Lastly, I note that this recommended ROE of 9.75% does not consider nor add to the ROE to account for PGE's business risk consideration which if considered would support a higher allowed ROE.

V. Capital Structure

Q. How did you determine the appropriate regulatory capital structure for 2025?

A. PGE's regulatory capital structure is based on the forecasted income statement and balance sheet for 2025. We also considered PGE's need to maintain 1) its financial strength; 2) flexibility and adequate liquidity; 3) reliable and economical access to the capital markets; 4) ability to minimize the cost of capital to customers and shareholders; and 5) Commission Order No. 23-386 in UE 416 and a capital structure consisting of 50% long-term debt and 50% equity.

Q. Has PGE issued any common equity recently?

A. Yes. In October 2022 PGE issued an equity forward of 11,615,000 shares. Shares issued in the equity forward were drawn throughout 2023. Through the end of 2023, PGE has entered into separate forward sale agreements for 1.7 million shares under its ATM program and will continue to execute under this program to support capital needs.

Q. Did the issuance of common equity impact PGE's overall capital structure?

A. Yes. This issuance of common equity will serve to increase PGE's equity capital and is an important tool to assist PGE in maintaining an overall 50/50 capital structure.

Q. Are you seeking a different regulatory capital structure than in UE 416?

A. No. In UE 416, the Commission adopted a settlement among the parties that reaffirmed PGE's regulated capital structure at 50% equity and 50% debt. PGE's long-term goal continues to be to maintain its 50/50 capital structure.

Q. Why does PGE not consider a more leveraged regulatory capital structure?

A. A 50% debt and 50% equity capital structure is the optimal debt-to-equity ratio for PGE because it offers a balance between the ideal debt-to-equity range and reduces PGE's cost of capital. The equity portion of PGE's capital structure is important because it represents how PGE finances its cash needs, which directly impacts customer prices. We believe the 50% equity in PGE's capital structure helps to better withstand difficult situations, such as under-earning due to events outside of PGE's control. It is also required to help offset the leverage imputed by the rating agencies due to purchased power agreements. PGE also faces risks in the banking environment due to its relatively small size, and it must maintain a solid capital structure and financial flexibility to manage customer costs and provide shareholder value.

Q. Aside from the risks discussed above, what other types of significant risks does PGE encounter today?

A. PGE encounters a variety of risks including:

- Weather which creates risks for PGE in several ways, including: power replacement costs due to lower than average stream flows; lower than average wind speeds and when the wind generates; and volatility in electricity usage because of sudden; and unexpected weather changes and severe storms and wildfires can increase expense and capital expenditures to mitigate and repair the impacts.
- Regional economic weakness can adversely affect PGE's revenues through a decline in electricity usage. A reduction in revenues can reduce PGE's profits, which negatively affects PGE's retained earnings and returns to investors. Lower retained earnings affect our ability to reinvest in the business.
- Uncertainty regarding financial and business operations contingencies are noted in PGE's Securities and Exchange Commission (SEC) annual 10-K and quarterly 10-Q

filings.[91] PGE could be target of cyber security and physical assets attacks. The electric industry is going through accelerated technological changes, which can make a basic premise of the current business model (economies of scale gained from central generation facilities) obsolete.

- Federal and state energy policy from legislative or regulatory efforts creates uncertainty and could lead to operating changes required of PGE to comply with existing or new laws which could materially increase PGE costs.

Q. Do the financial markets agree that these are risks for PGE?

A. Yes. Recent reports from various equity analysts include at least one of the risks listed above. We have included recent reports from Wells Fargo and Bank of America in our work papers.

Q. Can PGE mitigate these risks?

A. PGE can manage some of these risks, but not all. For risks that PGE can manage, PGE develops management capabilities and core competencies, as well as establishes strong processes and procedures to mitigate those risks. PGE is proactively implementing programs that will better prepare for operational impacts of adverse events. PGE's Wildfire Mitigation Plan, and the approach PGE has taken to constantly assess and update the plan, is an example of this commitment to proactive risk mitigation. Another example would be PGE's efforts to improve the ability to recover from catastrophic events, which remains a key strategic focus. PGE's Department of Business Continuity and Emergency Management has developed recovery plans to address disasters and implement emergency management procedures.

[91] https://investors.portlandgeneral.com/sec-filings/sec-filing/10-k/0000784977-24-000034. Starting with page 127, Note 19- 2023 SEC Form 10-K. https://investors.portlandgeneral.com/sec-filings/sec-filing/10-q/0000784977-23-000142. . Starting with page 29, Note 8- the most recent 10/27/2023 PGE SEC Form 10-Q.

We note, however, that there are risks that PGE cannot manage including those associated with the government or regulatory framework. For these types of risk, PGE ensures that it is prepared and capable of responding to them to the best of its ability and PGE continues to actively participate in the legislative and regulatory arenas.

Q. Could the risks addressed above alter the cost of capital you request?

A. Yes. If these risks result in financial distress to PGE and/or its peers, the cost of long-term debt and the cost of equity will increase, with a resulting long-term cost impact on customers through increased borrowing costs and possibly a ratings downgrade.

VI. Summary

Q. Please summarize PGE's requested overall cost of capital for this filing.

A. For the reasons described above, we request a 7.189% cost of capital for the 2025 test year. This cost of capital reflects PGE's updated request for return on equity (ROE) of 9.75%, its currently authorized capital structure of 50% debt and 50% equity, and an updated long-term cost of debt of 4.628%.

VII. Qualifications

Q. Mr. Liddle, please state your educational background and experience.

A. I received a Bachelor of Science in Business Administration with a finance emphasis from the University of Oregon in 2004 and a Master of Business Administration from Portland State University in 2009. I joined PGE's Corporate Finance Department in 2005 and have held a wide array of roles including Investor Relations, Treasury, Controller, Financial Planning & Analysis, Forecasting, Regulatory Affairs, and Utility Asset Management. In my current role I am responsible for Risk Management, Enterprise Risk Management, mid-Office operations, Tax, Financial Operations, Finance Systems, and Treasury. I also serve on the Board of Trustees for the Portland State University Foundation including its Finance and Audit Committees.

Q. Mr. Figueroa, please briefly describe your education and professional qualifications.

A. I have over 10 years of experience working in the regulated utility industry. At Brattle, my work is concentrated in energy finance, including cost of capital and related matters. I have worked with Brattle's testifying experts in preparing and filing cost of capital testimonies before regulators in multiple U.S. states, as well as before the Federal Energy Regulatory Commission and in Canada. I have also co-sponsored cost of capital testimonies in three jurisdictions. Prior to Brattle, I worked at Con Edison in several different roles, including electric operations and energy management.

I have a B.S. in Mechanical Engineering from Columbia University, a B.S. in Neuroscience from Brandeis University, and an M.B.A. from NYU's Stern School of Business. PGE Exhibit 603 contains more information on my professional qualifications as well as a list of my prior testimonies and publications.

List of Exhibits

Exhibit 601 contains confidential information and is subject to

General Protective Order 23-132

Standard & Poor's and Moody's Investors Service Credit Ratings

	S&P	Rating Date	Moody's	Rating Date
Senior Secured Debt	A	12/14/2023	A1	4/18/2023
Senior Unsecured	BBB+	12/14/2023	A3	4/18/2023
Short-term/ Commercial Paper	A-2	12/14/2023	P-2	4/18/2023

"Credit Opinion: Portland General Electric Company" December 14, 2023. Standard & Poor's
"Credit Opinion: Portland General Electric Company" April 18, 2023. Moody's Investors Service

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Mr. Josh Figueroa is a Senior Associate at The Brattle Group specializing in financial and economic topics in the energy sector with expertise in regulatory finance, natural gas utilities, energy commodity markets, and infrastructure development. Since joining Brattle, Mr. Figueroa has assisted electric, natural gas, water utilities, and airports on cost of capital and business risk matters in Alaska, California, Illinois, Michigan, New York, Oregon, Virginia Washington, Alberta, British Columbia, Quebec, and Barbados as well as before the Federal Energy Regulatory Commission. In addition to leading cost of capital analyses for Brattle experts, Mr. Figueroa has co-authored cost of capital testimony submitted before the New York Public Service Commission, the Oregon Public Utility Commission, and the Barbados Fair Trade Commission. Mr. Figueroa also provides regulatory due diligence assistance to potential acquisitions of regulated utilities and energy assets on matters such as return on equity, cost recovery, and the impacts of regulatory and legislative initiatives. Mr. Figueroa is also a co-leader of Brattle's Future of Gas practice and has assisted utilities and industry stakeholders develop strategies, utility programs, and alternative regulatory structures in response to the evolving landscape for natural gas utilities. Mr. Figueroa has co-authored Future of Gas expert testimony and reports submitted before the Massachusetts Department of Public Utilities and the British Columbia Utilities Commission.

Prior to joining Brattle, Mr. Figueroa was a founding member of Con Edison Transmission, where he led the acquisition, development, and management of electric and natural gas transmission assets. He began his career at Consolidated Edison Company of New York as an energy management analyst, where he was responsible for managing the capacity and supply portfolio for Con Edison's 1.2 million natural gas customers. Mr. Figueroa was also a natural gas purchaser and scheduler for Con Edison's regulated gas utilities and steam business unit. Mr. Figueroa has over 10 years of experience working in the regulated utility industry. Mr. Figueroa holds a Master of Business Administration from NYU's Stern School of Business, a B.S. in Mechanical Engineering from Columbia University, and a B.S. in Neuroscience from Brandeis University.

EDUCATION

NYU Stern School of Business, MBA with concentrations in Finance and Corporate Finance
Columbia University, B.S. Mechanical Engineering
Brandeis University, B.S. Neuroscience

AREAS OF EXPERTISE

Regulatory Finance

- Cost of Capital
- Regulatory Advisory in Mergers & Acquisitions

Natural Gas Utilities

- Future of Gas

Energy Commodity Markets

- Natural Gas Storage & Transportation Contracts

Damages and Valuation

- Infrastructure Development and Valuation
- Damages from Energy Litigation & Regulatory Disputes

TESTIMONY AND EXPERT REPORTS

Cost of Capital

- Cost of capital and business risk on behalf of Orange and Rockland Utilities, Inc. before the *New York Public Service Commission* (with Dr. Bente Villadsen), 24-E-0060 and 24-G-0061, January 2024

- Cost of capital and business risk on behalf of NW Natural before the *Oregon Public Utility Commission* (with Dr. Bente Villadsen), UG 435, December 2021.

- Cost of capital on behalf of Barbados Light & Power Company Ltd before the *Barbados Fair Trading Commission* (with Dr. Bente Villadsen), August 2021.

Future of Gas

- Response to Boston Gas Company D/B/A National Grid's Long-Range Resource and Requirement Plan, Expert Testimony filed on behalf of the Commonwealth of Massachusetts Office of the Attorney General before the *Massachusetts Department of Public Utilities* (with Dr. Dean Murphy), DPU-22-149, March 2023.

- Response to Petition of Liberty Utilities for approval of RNG supply contract, Expert Testimony filed on behalf of the Commonwealth of Massachusetts Office of the Attorney General before the *Massachusetts Department of Public Utilities* (with Dr. Dean Murphy), DPU-22-32, July 2022.

- Independent Expert Report, "Renewable Natural Gas Supply and Demand in North America, Independent Expert Report on FortisBC Energy Inc. Biomethane Energy Recovery Charge Methodology and Comprehensive Review of Reviewed Renewable Gas Program." on behalf of the British Columbia Utilities Commission staff (with Dr. Dean Murphy and Dr. Long Lam), December 2022.

REPRESENTATIVE EXPERIENCES

Regulatory Finance

Recent and Ongoing Cost of Capital Cases

- Mr. Figueroa is leading the development of cost of capital and business risk testimony for two Canadian utilities.
- Mr. Figueroa led the ROE estimation analysis, employing CAPM, DCF, and Implied Risk Premium financial models, conducted a business risk assessment, and co-sponsored Direct Testimony (with Dr. Bente Villadsen) submitted before the New York Public Service Commission (24-E-0060 and 24-G-0061) on behalf of Orange and Rockland Utilities, Inc., January 2024.
- Mr. Figueroa led a cost of capital analysis for a group of state-owned airports as part of a rate negotiations with airlines.
- Mr. Figueroa supported a Brattle Principal to develop cost of capital testimony for an interstate natural gas pipeline before the Federal Energy Regulatory Commission.
- Mr. Figueroa supported a Brattle Principal to develop cost of capital testimony for a natural gas pipeline before the Canadian Energy Regulator.
- Mr. Figueroa assisted in the preparation of rebuttal testimony for a Brattle expert for submission before the Michigan Public Service Commission on behalf of DTE Gas (Docket No. U-21291), January 2024.
- Mr. Figueroa supported two Brattle Principals in developing testimony and analyses ATCO Utilities, FortisAlberta, and Apex Utilities in the Alberta Utilities Commission's "Determination of the Cost-of-Capital Parameters in 2024 and Beyond" proceeding (27084).
- Mr. Figueroa supported a Brattle Principal by drafting rebuttal and surrebuttal cost of capital testimony submitted before the Illinois Commerce Commission (ICC Docket 23-0055) on behalf of Commonwealth Edison, January 2023.
- Mr. Figueroa led the ROE estimation analyses, employing CAPM, DCF, and Implied Risk Premium financial models, conducted a business risk assessment, and assisted in the preparation of a Brattle Principal's testimony submitted before the Illinois Commerce Commission (ICC Docket 23-0066) on behalf of Nicor Gas Company, January 2023

- Mr. Figueroa led the ROE estimation analysis, employing CAPM, DCF, and Implied Risk Premium financial models, conducted a business risk assessment, and assisted in the preparation of a Brattle Principal's direct testimony for submission before the Commonwealth of Virginia State Corporation Commission (Docket No. PUR-2022-00052) on behalf of Virginia Natural Gas, August 2022

- Mr. Figueroa led the ROE estimation analysis, employing CAPM, DCF, and Implied Risk Premium financial models, conducted a business risk assessment, and co-sponsored Direct Testimony (with Dr. Bente Villadsen) submitted before the Oregon Public Utility Commission (UG 435) on behalf of NW Natural, December 2021

- Mr. Figueroa led the ROE estimation analyses, employing CAPM, DCF, and Implied Risk Premium financial models, performed a capital structure analysis, and assisted in the preparation of direct testimony for a Brattle expert for submission before the Régie de l'énergie du Quebec on behalf of Énergir, Gazifère, and Intragaz (R-4156-2021), November 2021.

- Mr. Figueroa led the ROE estimation analysis, employing CAPM, DCF, and Implied Risk Premium financial models, conducted a business risk assessment, and co-authored the expert report (with Dr. Bente Villadsen) submitted before the Barbados Fair Trading Commission on behalf of Barbados Light & Power, October 2021

- Mr. Figueroa led the ROE estimation analysis, employing CAPM, DCF, and Implied Risk Premium financial models, conducted a business risk assessment, and assisted in the preparation of direct and rebuttal testimony for a Brattle expert for submission before the Public Utilities Commission of the State of California on behalf of California Water (A.21-05-002), May 2021.

- Mr. Figueroa assisted the ROE estimation analysis for a FERC-jurisdictional natural gas pipeline company, using CAPM and DCF models consistent with Order 569-A. He assisted in the preparation of direct testimony for a Brattle expert for submission before the FERC on behalf of Southern Star Central Gas Pipeline (RP21-778), April 2021.

- Mr. Figueroa led the ROE estimation analyses, employing CAPM, DCF, and Implied Risk Premium financial models, and assisted in the preparation of direct, rebuttal, and surrebuttal testimony for a Brattle expert for submission before the Illinois Commerce Commission on behalf of Nicor Gas (Docket No. 18-1775), January 2021.

- Mr. Figueroa assisted in the ROE estimation analyses, employing CAPM, DCF, and Implied Risk Premium financial models and conducted a business risk assessment, and assisted in the preparation of direct and rebuttal testimonies for a Brattle expert for submission before the State of New York

Public Service Commission on behalf of Orange & Rockland Utilities (Docket 21-G-0073 and 21-E-0074), January 2021.

- Mr. Figueroa assisted in the ROE estimation analyses, employing CAPM, DCF, and Implied Risk Premium financial models, conducted a business risk assessment, and assisted in the preparation of direct testimony for a Brattle expert for submission before the Regulatory Commission of Alaska on behalf of Anchorage Water & Wastewater (Docket No. TA168-122), December 2020.

- Mr. Figueroa led the ROE estimation analyses employing CAPM, DCF, and Implied Risk Premium financial models, led a business risk assessment, and assisted in the preparation of direct testimony for a Brattle expert for submission before the Washington Utilities and Transportation Commission on behalf of NW Natural (Docket No. UG-200994), December 2020.

- Mr. Figueroa assisted in the preparation of rebuttal testimony for a Brattle expert for submission before the Michigan Public Service Commission on behalf of DTE Gas (Docket No. U-20642), April 2020

- Mr. Figueroa led the ROE estimation analyses employing CAPM, DCF, and Implied Risk Premium financial models, and assisted in the preparation of direct testimony for a Brattle expert for submission before the Alberta Utilities Commission on behalf of ATCO Utilities, FortisAlberta, and AltaGas Utilities in the 2020 Generic Cost of Capital Proceeding, November 2019.

Regulatory Advisory in Due Diligence

- Mr. Figueroa is assisting a utility evaluate options to develop utility-owned renewable generation projects. Brattle is evaluating the regulatory and policy landscape for utility-owned generation, conducting analyses to quantify the costs to customers under this ownership structure, and how such a strategy would help achieve the state's energy policy goals.

- For various potential acquirers of electric and natural gas utilities, electric transmission assets, and power generation assets, Mr. Figueroa has assisted with regulatory due diligence related to the regulatory environment where the assets are located, the ability to earn the allowed return and cost recovery associated with capital expenditures. Mr. Figueroa's regulatory due diligence work spans multiple client engagements across four U.S. state regulatory environments and the FERC.

Energy Litigation

- Mr. Figueroa assisted an outside expert develop and submit testimony before the United States District Court for the District of Puerto Rico in the bankruptcy proceeding of the Puerto Rico Electric Power Authority (Case No. 17-BK-4780-LTS), January 2024.

- Mr. Figueroa assisted a Brattle Principal develop and submit an expert report before the London Court of International Arbitration related to natural gas transactions during the February 2021 Winter Storm Uri event.

- Mr. Figueroa assisted two Brattle experts to develop and submit expert reports before the London Court of International Arbitration related to natural gas supply costs and physical gas trading during Winter Storm Uri.

- Mr. Figueroa assisted a Brattle expert to develop and submit evidence before the Minnesota Public Utilities Commission on behalf of Northern States Power regarding the reasonableness of natural gas commodity costs incurred during the February 2021 Winter Storm Uri (Docket No. OAH 71-2500-37763; PUC CI-21-610).

- Mr. Figueroa assisted a Brattle expert develop and submit an expert report in U.S. District Court regarding a commercial dispute of a natural gas power plant development project. Mr. Figueroa led the evaluation of damages under three formulations contemplated by the tolling agreement. As part of that, he also assisted in the evaluation of electricity capacity markets in the region.

- Mr. Figueroa led development of expert report in U.S. District Court regarding a commercial dispute of a merchant natural gas power plant development project. Mr. Figueroa led the development of the financial model to quantify damages under various damage assessment methodologies.

- Mr. Figueroa assisted a Brattle expert develop and submit an expert report before the International Centre for Dispute Resolution (ICDR) regarding a commercial dispute at an LNG liquefaction facility. Mr. Figueroa led the development of the financial model to quantify damages.

Future of Gas

- Mr. Figueroa supported a client develop comments and submit comments to the U.S. Department of Treasury related to the proposed clean hydrogen tax credits (“Section 45V”).

- Mr. Figueroa is supporting a client participate in a docket before the New York Public Service Commission related to New York State Electric & Gas Company’s and Rochester Gas and Electric’s Long Term Plan. The Long Term Plans lay out the companies’ natural gas infrastructure and supply plans that comply with New York’s climate and energy policy goals.

- Mr. Figueroa is co-leading a project with the National Association of Regulatory Utility Commissioners (NARUC) to facilitate a series of workshops and learning sessions as part of their Task Force on Natural Gas Resource Planning. The Task Force is comprised of Commissioners and staff from 21 state utility commissions.

- Mr. Figueroa is supporting a client to negotiate an electric transmission tariff for a green ammonia export facility. The facility will produce green ammonia that meets the emissions criteria under the European Commission's Renewable Fuels of Non-Biological Origin (RFNBO) standard. The electric transmission tariff will interconnect the developer's 500 MW wind farm to power the facility; provide top-up and spill balancing; and firm-back up to critical components of the facility.

- Mr. Figueroa led a Brattle team to assess the economics of blending hydrogen into gas utility distribution systems. The study is analyzing the cost of blending green (electrolysis with renewable power), pink (electrolysis with nuclear power), and blue (steam methane reformation + carbon capture) hydrogen and the achieved emission reductions versus other gas decarbonization technologies (electrification and RNG) in California, the Northeast, and the Gulf Coast.

- Mr. Figueroa supported a Principal who filed future of gas testimony on behalf of Peoples' Gas in its general rate case before the Illinois Commerce Commission. The testimony discusses the appropriate venue to analyze and address future of gas issues. (ICC Docket No. 23-0068 and 23-0069)

- Mr. Figueroa is supporting a Brattle team evaluate and compare the cost, implementation timeline, and energy penalty associated with long-distance transportation of clean energy via high voltage direct current (HVDC) transmission lines versus a transportation via a hydrogen pipeline.

- Mr. Figueroa led a team that analyzed the role that hydrogen-fired generation could play in a high renewable penetration future. Brattle evaluated the economics and technology considerations of hydrogen-fired generation compared to other clean dispatchable resources, such as battery story, advanced nuclear, natural gas-fired generation with carbon capture and sequestration, and load flexibility.

- Mr. Figueroa co-sponsored testimony on behalf of the Massachusetts Attorney General's Office in connection with Boston Gas d/b/a National Grid's Long-Range Resource and Requirements Plan as part of as part of the Massachusetts Department of Public Utilities 22-32 Proceeding.

- Mr. Figueroa is co-leading a team to support the Rhode Island Office of Energy Resources as part of its involvement in the Rhode Island Public Utilities Commission Docket No. 22-01-NG, Investigation into the Future of the Regulated Gas Distribution Business in Rhode Island in Light of the Act on Climate.

- Mr. Figueroa co-led a Brattle team supporting the Massachusetts Executive Office of Energy and Environmental Affairs ("EEA") to develop the Massachusetts Clean Energy and Climate Plan for 2050.

- Mr. Figueroa co-sponsored an expert report on behalf of the British Columbia Utilities Commission to evaluate the supply and demand of renewable natural gas in North America, as part of a docket reviewing FortisBC Energy's application for a renewable gas program. Filed December 6, 2022.
- Mr. Figueroa co-sponsored testimony on behalf of the Massachusetts Attorney General's Office in connection with Liberty Utilities' petition for approval of a twenty-year renewable natural gas (RNG) purchase and sale agreement as part of as part of the Massachusetts Department of Public Utilities 22-32 Proceeding.
- Mr. Figueroa is supporting a Brattle Principal who submitted expert testimony on behalf of Peoples' Gas in a dispute over the prudence of the utility's leak prone pipe replacement program costs and the appropriate standards for cost recovery (ICC Docket No. 17-0137).
- Mr. Figueroa co-led a team to perform a market need assessment on behalf of a natural gas storage developer who has filed an application before FERC its existing storage facility in the Rocky Mountain region.
- Mr. Figueroa is co-leading a team to provide regulatory and technical consulting services to support the Massachusetts Attorney General's Office as part of its involvement in the Massachusetts Department of Public Utilities 20-80 Proceeding "Investigation into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals."
- Mr. Figueroa co-led a team to provide advisory services to a stakeholder as part of the Massachusetts Department of Public Utilities 21-118 Proceeding regarding Eversource Gas Company of Massachusetts' Forecast & Supply Plan filings.
- Mr. Figueroa co-led a team to support a Mid-Atlantic natural gas utility to develop a gas energy efficiency (EE) and demand response (DR) pilot programs as part of EmPOWER Maryland.
- For a Mid-Atlantic natural gas utility, Mr. Figueroa co-led a team to analyze the market potential for a residential, commercial, and industrial natural gas demand response program. The assessment included a Bring Your Own Thermostat program, direct load control for space heating and water heating, pricing program, and behavioral demand response.
- Mr. Figueroa assisted in the development of a system dynamics model for a client to study the impact of natural gas decarbonization on ratepayers and utility finances, under different customer adoption, technology costs, and rate design scenarios. System dynamics evaluates the dynamic feedbacks on each of these components to provide new perspectives on the regulatory and policy impacts on gas decarbonization.

- Mr. Figueroa assisted in the development of a benefit-cost analysis framework for a natural gas and electric utility as part of New York's Non-Pipeline Alternatives (NPA) initiative. As part of the utility planning process, the New York State Public Service Commission requires utilities to pursue investments in energy efficiency, clean demand response, and electrification to reduce, defer, or eliminate the need for gas infrastructure investments. The NPA framework evaluates the impact utility supply costs, capital and O&M expenses, customer impacts, GHG emissions, and other associated benefits and costs.

- Mr. Figueroa led a marginal cost of service (MCOS) study to quantify the benefits and costs associated with the utility's Non-Pipe Alternative (NPA) programs.

- Mr. Figueroa led a project to analyze the evolving role that natural gas generators will play in a high renewable penetration world and the impact gas generators will have on gas utilities. Specifically, how should gas utility tariffs change to recover costs associated with providing balancing services to generators and to equitably share gas utility system costs amongst an evolving customer base.

SPEAKING ENGAGEMENTS

- Bank of America Securities 2023 Hydrogen Conference, "Role of Hydrogen in a Decarbonized Future," with Andrew Thompson, December 19, 2023.

- Alternative Power Plays Podcast, "The Primer on Hydrogen Power," with Ragini Sreenath, November 9, 2023.

- National Association of Regulatory Utility Commissioners (NARUC) Summer Policy Summit, "How Electrification of Buildings and Transportation Impacts Regulation of Electric and Gas Distribution Systems," July 17, 2023.

- Alternative Power Plays Podcast, "Decarbonization of the Utilities Sector," with Jay Balasbas (former Commissioner at the Washington Utilities and Transportation Commission), August 24, 2022.

- Association of Energy Service Professionals (AESP), "Natural gas demand response programs – the time is NOW!" panel, August 17, 2022.

- National Association of Regulatory Utility Commissioners (NARUC) Summer Policy Summit, "Navigating Gas Utilities to a Decarbonized and Financially Sound Future," July 19, 2022.

- The Brattle Group, Future of Gas Utility Symposium, moderator for "Assessing Risks & Opportunities" panel, December 7, 2021.

- "Impacts and Implications of COVID-19 for the Energy Industry" with Tess Counts. Presented to the National Rural Utilities Cooperate Finance Corporation, May 13, 2020.

PUBLICATIONS

- John Tsoukalis, Josh Figueroa, Ragini Sreenath, Ellie Curtis, "Section 45V Clean Hydrogen Production Tax Credits, Comments on Proposed Treasury Guidelines" February 2024.

- Frank Graves, Josh Figueroa, Ragini Sreenath, Lorenzo Sala, Jadon Grove, Stephen Thumb, "Emerging Economics of Hydrogen Production and Delivery," February 2024.

- Josh Figueroa, Ragini Sreenath, Metin Celebi, Sylvia Tang, John Gonalez, Sam Willet, "DOE Regional Clean Hydrogen Hubs Program (H2Hubs)," November 2023.

- Frank C. Graves, Metin Celebi, Josh Figueroa, Tess Counts, Evan Bennet, Sylvia Tang, Shreeansh Agrawal, Steve Thumb, "Impact of Russia/Ukraine War on World Natural Gas & Oil Markets," March 28, 2022.

- Frank C. Graves, Long Lam, Josh Figueroa, Kasparas Spokas, Tess Counts, Maria Castaner, Katie Mansur, Shreeansh Agrawal, "The Future of Gas Utilities Series: Part 3 – Implementing Regulations," November 2021.

- Frank C. Graves, Kasparas Spokas, Josh Figueroa, Long Lam, Tess Counts, Maria Castaner, Katie Mansur, Shreeansh Agrawal, "The Future of Gas Utilities Series: Part 2 – Evaluating Strategies," September 2021.

- Bente Villadsen, Josh Figueroa, Tess Counts, "Utility Allowed Return on Equity in New York," September 17, 2021. Confidential.

- Frank C. Graves, Josh Figueroa, Long Lam, Kasparas Spokas, Tess Counts, Maria Castaner, Katie Mansur, Shreeansh Agrawal, "The Future of Gas Utilities Series: Part 1 – Assessing Risks & Opportunities," August 2021.

- Frank C. Graves, Robert S. Mudge, Josh Figueroa, Lily Mwalenga, Tess Counts, Katie Mansur, and Shivangi pant, "Impacts and Implications of COVID-19 for the Energy Industry: Assessment through Mid-October," November 2, 2020.

- Frank C. Graves, Robert S. Mudge, Josh Figueroa, Tess Counts, Lily Mwalenga, and Shivangi pant, "Impacts and Implications of COVID-19 for the Energy Industry: Assessment through June 2020," July 9, 2020.

- Bente Villadsen, Robert S. Mudge, Frank C. Graves, Josh Figueroa, Tess Counts, Lily Mwalenga, and Shivangi Pant, "Global Impacts and Implications of COVID-19 on Utility Finance," June 30, 2020.
- Frank C. Graves, Tess Counts, Josh Figueroa, Robert S. Mudge, Shivangi Pant, and Lily Mwalenga, "Impacts and Implications of COVID-19 for the US Energy Industry," May 12, 2020.
- Josh Figueroa, Tess Counts, Frank C. Graves, Robert S. Mudge, and Shivangi Pant, "Impact of COVID-19 on the US Energy Industry," April 14, 2020.

Technical Appendix to the Direct Testimony of Josh Figueroa

This technical appendix contains methodological details related to my implementations of the DCF and CAPM / ECAPM models. It also contains a discussion of both the basic finance principles and the specific standard formulations of the financial leverage adjustments employed to determine the cost of equity for a company with the level of financial risk inherent in Portland General's requested regulatory capital structure.

Table of Contents

I. CAPM and ECAPM

A. THE CAPITAL ASSET PRICING MODEL (CAPM)

The Capital Asset Pricing Model (CAPM) is a theoretical model stating that the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market as a whole. The CAPM posits a risk-return relationship known as the Security Market Line (see Figure 2 in my Direct Testimony), in which the required expected return on an asset is proportional to that asset's risk relative to the market as measured by its "beta." More precisely, the CAPM states that the cost of capital for an investment S (e.g., a particular common stock), is given by the following equation:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \tag{1}$$

where $\boldsymbol{r_S}$ is the required return on investment S;
$\boldsymbol{r_f}$ is the risk-free interest rate;
$\boldsymbol{\beta_S}$ is the beta risk measure for the investment S; and
$\boldsymbol{MRP}$ is the market equity risk premium.

The CAPM is based on portfolio theory, and recognizes two fundamental principles of finance: (1) investors seek to minimize the possible variance of their returns for a given level of expected returns (or alternatively, they demand higher *expected* returns when there is greater uncertainty about those returns), and (2) investors can reduce the variability of their returns by diversifying—constructing portfolios of many assets that do not all go up or down at the same time or to the same degree. Under the assumptions of the CAPM, the market participants will construct portfolios of risky investments that minimize risk for a given return so that the aggregate holdings of all investors represent the "market portfolio." The risk-return trade-off faced by investors then concerns their exposure to the risk inherent in the market portfolio, as they weigh their investment capital between the portfolio of risky assets and the risk-free asset.

Because of the effects of diversification, the relevant measure of risk for an individual security is its *contribution* to the risk of the market portfolio. Therefore, beta (β) is defined to capture the sensitivity of the security's returns to the market's returns. Formally,

$$\boldsymbol{\beta}_s = \frac{covariance(\boldsymbol{r_s}, \boldsymbol{R_m})}{variance(\boldsymbol{R_m})} \tag{2}$$

where $\boldsymbol{R_m}$ is the return on the market portfolio.

Beta is usually calculated by statistically comparing (using regression analysis) the excess (positive or negative) of the return on the individual security over the government bond rate with the excess of the return on a market index such as the S&P 500 over a government bond rate.

The basic idea behind beta is the risk that cannot be diversified away in large portfolios is what matters to investors. Beta is a measure of the risks that *cannot* be eliminated by diversification. It is this non-diversifiable risk, or "systematic risk," for which investors require compensation in the form of higher expected returns. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk; its returns vary to the same degree as those on the market as a whole. According to the CAPM, the required return demanded by investors (i.e., the cost of equity) for investing in that stock will match the expected return on the market as a whole. Similarly, stocks with betas above 1.0 have more than average risk, and so have a cost of equity greater than the expected market return; those with betas below 1.0 have less than average risk and are expected to earn lower than market levels of return.

B. INPUTS TO THE CAPM

1. The Risk-free Interest Rate

The precise meaning of a "risk-free" asset according to the finance theory underlying the CAPM is an investment whose return is guaranteed, with no possibility that it will vary around its expected value in response to the movements of the broader market. (Equivalently, the CAPM beta of a risk-free asset is zero). In developed economies like the U.S., government debt is generally considered to have no default risk. In this sense they are "risk-free"; however, unless they are held to maturity, the rate of return on government bonds may in fact vary around their stated or expected yields.[1]

[1] This is due to interest rate fluctuations that can change the market value of previously issued debt in relation to the yield on new issuances.

The theoretical CAPM is a single period model, meaning that it posits a relationship between risk and return over a single "holding period" of an investment. Because investors can rebalance their portfolios over short horizons, many academic studies and practical applications of the CAPM use the short-term government bond as the measure of the risk-free rate of return. However, regulators frequently use a version based on a measure of the long-term risk-free rate, e.g., a long-term government bond. I rely on the 20-year Treasury bond as a measure of the risk-free asset in this proceeding.[2] I use the term "risk-free rate" as describing the yield on the 20-year Treasury bond.

However, I do not believe the *current* yield on long-term Treasury bonds is a good estimate for the risk-free rate that will prevail over the time period relevant to this proceeding. Instead, I believe it is more important to use the yield that is expected to prevail during the rate period.[3] For this reason I rely on *Blue Chip Economic Indicators*' forecast of 3.7% for the yield on a 10-year Treasury bond for 2025.[4] I adjust this value upward by 50 basis points, which is my estimate of the maturity premium for the 20-year over the 10-year Treasury bond. This provides us with an estimate of the risk-free rate of 4.2% for 2025.

2. The Market Equity Risk Premium

a. Historical Average Market Risk Premium

Like the cost of capital itself, the market risk premium is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can *expect* to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable and must be inferred or forecasted based on known market information.

One commonly used method for estimating the MRP is to measure the historical average premium of market returns over the income returns on risk-free government bonds over some long historical period. When such a calculation is performed using the traditional industry standard Ibbotson data, the result is an arithmetic average of the annual observed premiums of

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2 The use of a 20-year government bond is consistent with the measurement of the Ibbotson MRP and permits us to use a series that has been in consistent circulation since the 1990's (the 30-year government bond was not issued from 2002 to 2006).

3 At the end of the technical appendix, I provide a version of the CAPM results which use current bond yields.

4 Wolters Kluwer, Blue Chip Economic Indicators, Vol. 49 No. 1, January 10, 2024, p. 3.

U.S. stock market returns over income returns on long-term (approximate average maturity of 20-years) U.S. Treasury bonds from 1926 to the present is 7.17%.[5]

b. Forward Looking Market Equity Risk Premium

An alternative approach to estimating the MRP eschews historical averages in favor of using current market information and forecasts to infer the expected return on the market as a whole, which can then be compared to prevailing government bond yields to estimate the equity risk premium. Bloomberg performs such estimates of country-specific MRPs by implementing the DCF model on the market as a whole—using forecast market-wide dividend yields and current level on market indexes; for the U.S. Bloomberg performs a multi-stage DCF using dividend-paying stocks in the S&P 500 to infer the expected market return.

When calculated relative to 20-year Treasury bond yields, Bloomberg's estimate of the forward-looking market-implied MRP over the month leading up to my analysis was 6.37%.[6] This Bloomberg forward-looking MRP estimate is below the historical long-term average. Of note, the forward-looking MRP using the methodology from the FERC Order 569-A current results in a forward-looking MRP of approximately 7.87%.[7]

C. THE EMPIRICAL CAPM

1. Description of the ECAPM

Empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding, but the observation itself can also be used to estimate the cost of capital directly, using beta to measure relative risk by making a direct empirical adjustment to the CAPM.

The Empirical CAPM (ECAPM) makes use of these empirical findings. It estimates the cost of capital with the equation,

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5 Kroll Cost of Capital Navigator, U.S. Cost of Capital Module, accessed January 4, 2024, value as of December 31, 2022.

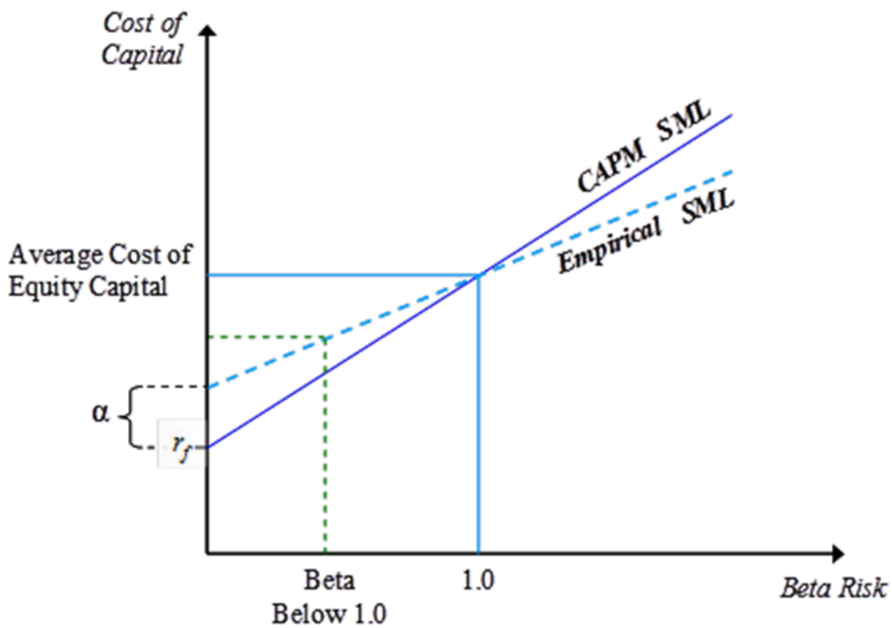
6 Bloomberg, as of December 31, 2023.

7 PGE Exhibit 605C.

$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \quad (3)$$

where α is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see Equation (1)). The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line, which results in a Security Market Line that more closely matches the results of empirical tests. In other words, the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

Figure B-2
The Empirical Security Market Line



2. Academic Evidence on the Alpha Term in the ECAPM

Figure B-3 below summarizes the empirical results of tests of the CAPM, including their estimates of the "alpha" parameter necessary to improve the accuracy of the CAPM's predictions of realized returns.

Figure B-3

EMPIRICAL EVIDENCE ON THE ALPHA FACTOR IN ECAPM*

AUTHOR	RANGE OF ALPHA	PERIOD RELIED UPON
Black (1993)[1]	1% for betas 0 to 0.80	1931-1991
Black, Jensen and Scholes (1972)[2]	4.31%	1931-1965
Fama and McBeth (1972)	5.76%	1935-1968
Fama and French (1992)[3]	7.32%	1941-1990
Fama and French (2004)[4]	N/A	
Litzenberger and Ramaswamy (1979)[5]	5.32%	1936-1977
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 3.91%	1926-1978
Pettengill, Sundaram and Mathur (1995)[6]	4.6%	1936-1990

*The figures reported in this table are for the longest estimation period available and, when applicable, use the authors' recommended estimation technique. Many of the articles cited also estimate alpha for sub-periods and those alphas may vary.

[1]Black estimates alpha in a one step procedure rather than in an un-biased two-step procedure.
[2]Estimate a negative alpha for the subperiod 1931-39 which contain the depression years 1931-33 and 1937-39.
[3]Calculated using Ibbotson's data for the 30-day treasury yield.
[4]The article does not provide a specific estimate of alpha; however, it supports the general finding that the CAPM underestimates returns for low-beta stocks and overestimates returns for high-beta stocks.
[5]Relies on Lizenberger and Ramaswamy's before-tax estimation results. Comparable after-tax alpha estimate is 4.4%.
[6]Pettengill, Sundaram and Mathur rely on total returns for the period 1936 through 1990 and use 90-day treasuries. The 4.6% figure is calculated using auction averages 90-day treasuries back to 1941 as no other series were found this far back.

Sources:
Black, Fischer. 1993. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18.
Black, F., Michael C. Jensen, and Myron Scholes. 1972. The Capital Asset Pricing Model: Some Empirical Tests, from Studies in the theory of Capital Markets. In *Studies in the Theory of Capital Markets*, edited by Michael C. Jensen, 79-121. New York: Praeger.
Fama, Eugene F. and James D. MacBeth. 1972. Risk, Returns and Equilibrium: Empirical Tests. *Journal of Political Economy* 81 (3): 607-636.
Fama, Eugene F. and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): 427-465.
Fama, Eugene F. and Kenneth R. French. 2004. The Capital Asset Pricing Model: Theory and Evidence. *Journal of Economic Perspectives* 18 (3): 25-46.
Litzenberger, Robert H. and Krishna Ramaswamy. 1979. The Effect of Personal Taxes and Dividends on Capital Asset Prices, Theory and Empirical Evidence. *Journal of Financial Economics* XX (June): 163-195.
Litzenberger, Robert H. and Krishna Ramaswamy and Howard Sosin. 1980. On the CAPM Approach to Estimation of a Public Utility's Cost of Equity Capital. *The Journal of Finance* 35 (2): 369-387.

II. DCF Models

A. DCF Estimation of Cost of Equity

The DCF method for estimating the cost of equity capital assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \tag{4}$$

where P_0 is the current market price of the stock; D_t is the dividend cash flow expected at the end of period t; r is the cost of equity capital; and T is the last period in which a dividend cash flow is to be received. The formula simply says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received. Since the current market price is known, it is possible to infer the cost of equity that corresponds to that price and a forecasted pattern of expected future dividends. In terms of Equation (4), if P_0 is known and $D_1, D_2, \ldots D_T$ are estimated, an analyst can "solve for" the cost of equity capital r.

B. Details of the DCF Model

Perhaps the most widely known and used application of the DCF method assumes that the expected rate of dividend growth remains constant forever. In the so-called Gordon Growth Model, the relationship expressed in Equation (4) is such that the present value equation can be rearranged algebraically into a formula for estimating the cost of equity. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, then the market price of the stock will be given by

$$P_0 = \frac{D_1}{r-g} \tag{5}$$

where D_1 is the dividend expected at the end of the first period, g is the perpetual growth rate, and P_0 and r are the market price and the cost of capital, as before. Equation (5) is a simplified version of Equation (4) that can be solved algebraically to yield the well-known "DCF formula" for the cost of equity capital,

$$r = \frac{D_1}{P_0} + g = \frac{D_0 \times (1+g)}{P_0} + g \qquad (6)$$

There are other versions of the DCF model that relax this restrictive assumption and posit a more complex or nuanced pattern of expected future dividend payments. For example, if there is reason to believe that investors do *not* expect a company's dividends to grow at a steady rate forever, but rather have different growth rate expectations in the near term (e.g., over the next five or ten years), compared to the distant future (e.g., a period *starting* ten years from the present moment), a "multi-stage" growth pattern can be modeled in the present value formula (Equation (4)).

1. Dividends, Cash Flows, and Share Repurchases

In addition to the DCF model described above, there are many alternative formulations. Notable among these are versions of the model that use cash flows rather than dividends in the present value formula (Equation (4)).[8]

Because investors are interested in cash flow, it is technically important to capture *all* cash flows that are distributed to shareholders when estimating the cost of equity using the DCF method. In some circumstances, investors may expect to receive cash in forms other than dividends. An important example concerns the fact that many companies distribute cash to shareholders through share buybacks in addition to dividends. To the extent such repurchases are expected by investors, but not captured in the forecasted pattern of future dividends; a dividend-based implementation of the DCF model will underestimate the cost of equity.

Similarly, if investors have reason to suspect that a company's dividend payments will not reflect a full distribution of its available cash free cash flows in the period they were generated, it may be appropriate replace the forecasted dividends with estimated free cash flows to equity in the present value formula (Equation (4)). Focusing on *available* cash rather than that actually distributed in the form of dividends can help account for instances when near-term investing and

[8] For an example in a regulatory context, the U.S. Surface Transportation Board uses a cash flow-based model with three stages to estimate the cost of equity for the railroads. See Surface Transportation Board Decision, "STB Ex Parte No. 664 (Sub-No. 1)," Decided January 23, 2009. Confirmed in EP-664 (Sub-No. 2), October 31, 2016 and EP 664 (Sub-No. 4), June 23, 2020.

financing activities (e.g., capital expenditures or asset sales, debt issuances or retirements, or share repurchases) may cause dividend growth patterns to diverge from growth in earnings.

Many utility companies such as those included in my proxy group have long histories of paying dividends. In fact, as mentioned in my Direct Testimony, one of my standard requirements for inclusion in my proxy group is that a company pays dividends for 5-years without a gap or a dividend cut in the past six months (on per share basis). Additionally, although some utility companies have engaged in share repurchase programs, the companies in my proxy group do not distribute substantial cash flows by means other than dividends.

C. DCF Model Inputs

1. Dividends and Prices

As described above, DCF models are forward-looking, comparing the *current* price of a stock to its expected *future* dividends to estimate the required expected return demanded by the market for that stock (i.e., the cost of equity). Therefore, the models demand the current market price and currently prevailing forecasts of future dividends as inputs.

The stock price input I employ for each proxy group company is the average of the closing stock prices for the 15 trading days ending on the date of my analysis. This guards against biases that may arise on a single trading day yet is consistent with using current stock prices.

2. Company Specific Growth Rates

a. Analysts' Forecasted Growth Rates

Finding the right growth rate(s) is usually the "hard part" of applying the DCF model, which is sometimes criticized due to what has been called "optimism bias" in the earnings growth rate forecasts of security analysts. Optimism bias is defined as the tendency for analysts to forecast earnings growth rates that are higher than are actually achieved. Any optimism bias might be related to incentives faced by analysts that provide rewards not strictly based upon the accuracy of the forecasts. To the extent optimism bias is present in the analysts' earnings forecasts, the cost of capital estimates from the DCF model would be too high.

While academic researchers during the 1990s as well as in early 2000s found evidence of analysts' optimism bias, there is some evidence that regulatory reforms have eliminated the issue. A more recent paper by Hovakimina and Saenyasiri (2010) found that recent efforts to curb analysts' incentive to provide optimistic forecasts have worked, so that "the median forecast bias essentially disappeared."[9] Thus, some recent research indicates that the analyst bias may be a problem of the past.

The findings of several academic studies show that analyst earnings forecasts turn out to be too optimistic for stocks that are more difficult to value, for instance, stocks of smaller firms, firms with high volatility or turnover, younger firms, or firms whose prospects are uncertain.[10] Coincidentally, stocks with greater analyst disagreement have higher analyst optimism bias—all of these describe companies that are more volatile and/or less transparent—none of which is applicable to the majority of utility companies with wide analyst coverage and information transparency. Consequently, optimism bias is not expected to be an issue for utilities.

b. Sources for Forecasted Growth Rates

For the reasons described above, I rely on analyst forecasts of earnings growth for the company-specific growth rate inputs to my implementations of the single- and multi-stage DCF models. Most companies in my proxy group have coverage from equity analysts reporting to Thomson Reuters *IBES*, so I use the consensus 3-5 year EPS growth rate provided by that service. I supplement these consensus values with growth rates based on EPS estimates from *Value Line*.[11]

III. Financial Risk and the Cost of Equity

A common issue in regulatory proceedings is how to apply data from a benchmark set of comparable securities when estimating a fair return on equity for the target/regulated

9 A. Hovakimina and E. Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts Journal*, vol. 66, 2010.

10 These studies include the following: (i) Hribar, P, McInnis, J. "Investor Sentiment and Analysts' Earnings Forecast Errors," *Management Science* Vol. 58, No. 2 (February 2012): pp. 293-307; (ii) Scherbina, A. (2004), "Analyst Disagreement, Forecast Bias and Stock Returns," downloaded from Harvard Business School Working Knowledge: http://hbswk.hbs.edu/item/5418.html; and (iii) Michel, J-S., Pandes J.A. (2012), "Are Analysts Really Too Optimistic?" downloaded from http://www.efmaefm.org.

11 Specifically, I compute the growth rate implied by *Value Line*'s current year EPS estimate and its projected 3-5 year EPS estimate. I then average this in with the IBES consensus estimate as an additional independent estimate, giving it a weight of 1 and weighting the IBES consensus according to the number of analysts who contributed estimates.

company.[12] It may be tempting to simply estimate the cost of equity capital for each of the proxy companies (using one of the above approaches) and average them. After-all, the companies were chosen to be comparable in their business risk characteristics, so why would an investor necessarily prefer equity in one to the other (on average)?

The problem with this argument is that it ignores the fact that underlying asset risk (i.e., the risk inherent in the lines of business in which the firm invests its assets) for each company is typically divided between debt and equity holders. The firm's debt and equity are therefore financial derivatives of the underlying asset return, each offering a differently structured claim on the cash flows generated by those assets. Even though the risk of the underlying assets may be comparable, a different capital structure splits that risk differently between debt and equity holders. The relative structures of debt and equity claims are such that higher degrees of debt financing increase the variability of returns on equity, *even when the variability of asset returns remains constant*. As a consequence, otherwise identical firms with different capital structures will impose different levels of risk on their equity holders. Stated differently, increased leverage adds financial risk to a company's equity.[13]

A. THE EFFECT OF FINANCIAL LEVERAGE ON THE COST OF EQUITY

To develop an intuition for the manner in which financial leverage affects the risk of equity, it is helpful to consider a concrete example. Figure B-4 and Figure B-5 below demonstrate the impact of leverage on the risk and return for equity by comparing equity's risk when a company uses no debt to finance its assets, and when it uses a 50-50 capital structure (i.e., it finances 50 percent of its assets with equity, 50 percent with debt). For illustrative purposes, the figures assume that the cash flows will be either \$5 or \$15 and that these two possibilities have the same chance of occurring (e.g., the chance that either occurs is ½).

12 This is also a common valuation problem in general business contexts.

13 I refer to this effect in terms of *financial risk* because the additional risk to equity holders stems from how the company chooses to finance its assets. In this context financial risk is distinct from and independent of the *business risk* associated with the manner in which the firm deploys its cash flow generating assets. The impact of leverage on risk is conceptually no different than that faced by a homeowner who takes out a mortgage. The equity of a homeowner who finances his home with 90% debt is much riskier than the equity of one who only finances with 50% debt.

Figure B-4: All Equity Capital Structure

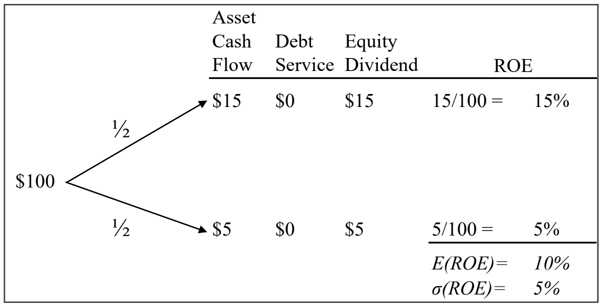
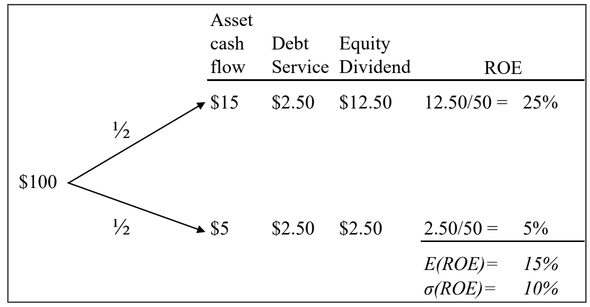


Figure B-5: 50/50 Capital Structure



In the figures, E(ROE) indicates the mean return and σ(ROE) represents the standard deviation. This simple example illustrates that the introduction of debt increases both the mean (expected) return to equity holders and the variance of that return, even though the firm's expected cash flows—which are a property of the line of business in which its assets are invested—are unaffected by the firm's financing choices. The "magic" of financial leverage is not magic at all—leveraged equity investors can only earn a higher return because they take on greater risk.

B. METHODS TO ACCOUNT FOR FINANCIAL RISK

1. Cost of Equity Implied by the Overall Cost of Capital

If the companies in a proxy group are truly comparable in terms of the systematic risks of the underlying assets, then the overall cost of capital of each company should be about the same across companies (except for sampling error), so long as they do not use extreme leverage or no leverage. The intuition here is as follows. A firm's asset value (and return) is allocated between equity and debt holders.[14] The expected return to the underlying asset is therefore equal to the

[14] Other claimants can be added to the weighted average if they exist. For example, when a firm's capital structure contains preferred equity, the term $\frac{P}{V} \times r_p$ is added to the expression for the overall cost of capital shown in Equation (7), where P refers to the market value of preferred equity, r_P is the cost of preferred equity and $V = E + D + P$. In our analysis, I attribute the same implied yield to the cost of preferred equity as to the cost of debt.

value weighted average of the expected returns to equity and debt holders – which is the overall cost of capital ($\boldsymbol{r}^*$), or the expected return on the assets of the firm as a whole.[15]

$$\boldsymbol{r}^* = \frac{E}{V} \times r_E + \frac{D}{V} \times r_D(1 - \tau_c) \qquad (7)$$

where r_D is the market cost of debt,
r_E is the market cost of equity,
τ_c is the corporate income tax rate,
D is the market value of the firm's debt,
E is the market value of the firm's equity, and
$V = E + D$ is the total market value of the firm.

Since the overall cost of capital is the cost of capital for the underlying asset risk, and this is comparable across companies, it is reasonable to believe that the overall cost of capital of the underlying companies should also be comparable, so long as capital structures do not involve unusual leverage ratios compared to other companies in the industry.[16]

The notion that the overall cost of capital is constant across a broad middle range of capital structures is based upon the Modigliani-Miller theorem that choice of financing does not affect the firm's value. Franco Modigliani and Merton Miller eventually won Nobel Prizes in part for their work on the effects of debt.[17] Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect

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15 As this is on an after-tax basis, the cost of debt reflects the tax value of interest deductibility. Note that the precise formulation of the weighted average formula representing the required return on the firm's *assets* independent of financing (sometimes called the *unlevered* cost of capital) depends on specific assumptions made regarding the value of tax shields from tax-deductible corporate debt, the role of personal income tax, and the cost of financial distress. See Taggart, Robert A., "Consistent Valuation and Cost of Capital Expressions with Corporate and Personal Taxes," *Financial Management*, 1991; 20(3) for a detailed discussion of these assumptions and formulations. Equation (7) represents the overall weighted average cost of capital to the firm, which can be assumed to be constant across a relatively broad range of capital structures.

16 Empirically, companies within the same industry tend to have similar capital structures, while typical capital structures may vary between industries, so whether a leverage ratio is "unusual" depends upon the company's line of business.

17 Franco Modigliani and Merton H. Miller (1958), "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48, pp. 261-297. For a modern textbook exposition of the capital structure theories, see Brealey, Myers, and Allen, op cit., Chapter 17.

on a company's operating cash flows (i.e., the cash flows to investors as a group, debt and equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, then the value of the firm cannot be affected at all by the debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

Obviously, the simple and elegant Modigliani-Miller theorem makes some counterfactual assumptions: no taxes and no cost of financial distress from excessive debt. However, subsequent research, including some by Modigliani and Miller,[18] showed that while taxes and costs to financial distress affect a firm's incentives when choosing its capital structure as well as its overall cost of capital,[19] the latter can still be shown to be constant across a broad range of capital structures.[20]

This reasoning suggests that one could compute the overall cost of capital for each of the proxy companies and then average to produce an estimate of the overall cost of capital associated with the underlying asset risk. Assuming that the overall cost of capital is constant, one can then re-arrange the overall cost of capital formula to estimate what the implied cost of equity is at the target company's capital structure on a book value basis.[21]

2. Unlevering and Relevering Betas in the CAPM (Hamada Adjustment)

An alternative approach to account for the impact of financial risk is to examine the impact of leverage on beta. Notice that this means working within the CAPM framework as the methodology cannot be applied directly to the DCF models.

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18 Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

19 When a company uses a high level of debt financing, for example, there is significant risk of bankruptcy and all the costs associated with it. The so called costs of financial distress that occurs when a company is over-leveraged can increase its cost of capital. In contrast a company can generally decrease its cost of capital by taking on reasonable levels of debt, owing in part to the deductibility of interest from corporate taxes.

20 This is a simplified treatment of what is generally a complex and on-going area of academic investigation. The roles of taxes, market imperfections and constraints, etc. are areas of on-going research and differing assumptions can yield subtly different formulations for how to formulate the weighted average cost of capital that is constant over all (or most) capital structures.

21 Market value capital structures are used in estimating the overall cost of capital for the proxy companies.

Recognizing that under general conditions, the value of a firm can be decomposed into its value with and without a tax shield, I obtain:[22]

$$V = V_U + PV(ITS) \tag{8}$$

where $V = E + D$ is the total value of the firm as in Equation (7), V_U is the "unlevered" value of the firm—its value if financed entirely by equity and $PV(ITS)$ represents the present value of the interest tax shields associated with debt

For a company with a fixed book-value capital structure and no additional costs to leverage, it can be shown that the formula above implies:

$$r_E = r_U + \frac{D}{E}(1 - \tau_c)(r_U - r_D) \tag{9}$$

where r_U is the "unlevered cost of capital"—the required return on assets if the firm's assets were financed with 100% equity and zero debt—and the other parameters are defined as in Equation (7).

Replacing each of these returns by their CAPM representation and simplifying them gives the following relationship between the "levered" equity beta β_L for a firm (i.e., the one observed in market data as a consequence of the firm's actual market value capital structure) and the "unlevered" beta β_U that would be measured for the same firm if it had no debt in its capital structure:

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \tag{10}$$

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[22] This follows development in Fernandez (2003). Other standard papers in this area include Hamada (1972), Miles and Ezzell (1985), Harris and Pringle (1985), Fernandez (2006). (See Fernandez, P., "Levered and Unlevered Beta," IESE Business School Working Paper WP-488, University of Navarra, Jan 2003 (rev. May 2006); Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock," *Journal of Finance*, 27, May 1972, pp. 435-452; Miles, J.A. and J.R. Ezzell, "Reformulating Tax Shield Valuation: A Note," *Journal of Finance*, XL5, Dec 1985, pp. 1485-1492; Harris, R.S. and J.J. Pringle, "Risk-Adjusted Discount Rates Extensions form the Average-Risk Case," *Journal of Financial Research*, Fall 1985, pp. 237-244; Fernandez, P., "The Value of Tax Shields Depends Only on the Net Increases of Debt," IESE Business School Working Paper WP-613, University of Navarra, 2006.) Additional discussion can be found in Brealey, Myers, and Allen (2014).

where β_D is the beta on the firm's debt. The unlevered beta is assumed to be constant with respect to capital structure, reflecting as it does the systematic risk of the firm's assets. Since the beta on an investment grade firm's debt is much lower than the beta of its assets (i.e., $\beta_D < \beta_U$), this equation embodies the fact that increasing financial leverage (and thereby increasing the debt-to-equity ratio) increases the systematic risk of *levered* equity (β_L).

An alternative formulation derived by Harris and Pringle (1985) provides the following equation that holds when the market value capital structures (rather than book value) are assumed to be held constant:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \qquad (11)$$

Unlike Equation (10), Equation (11) does not include an adjustment for the corporate tax deduction. However, both equations account for the fact that increased financial leverage increases the systematic risk of equity that will be measured by its market beta. And both equations allow an analyst to adjust for differences in financial risk by translating back and forth between β_L and β_U. In principle, Equation (10) is more appropriate for use with regulated utilities, which are typically deemed to maintain a fixed book value capital structure. However, I employ both formulations when adjusting my CAPM estimates for financial risk and consider the results as sensitivities in my analysis.

It is clear that the beta of debt needs to be determined as an input to either Equation (10), or Equation (11). Rather than estimating debt betas, I rely on the standard financial textbook of Professors Berk & DeMarzo, who report a debt beta of 0.05 for A-rated debt and a beta of 0.10 for BBB rated debt.[23]

Once a decision on debt betas is made, the levered equity beta of each proxy company can be computed (in this case by *Value Line*) from market data and then translated to an unlevered beta at the company's market value capital structure. The unlevered betas for the proxy companies are comparable on an "apples to apples" basis, since they reflect the systematic risk inherent in the assets of the proxy companies, independent of their financing. The unlevered betas are averaged to produce an estimate of the industry's unlevered beta. To estimate the cost of equity

23 Berk, J. & DeMarzo, P., *Corporate Finance, 2nd Edition.* 2011 Prentice Hall, p. 389.

for the regulated target company, this estimate of unlevered beta can be "re-levered" to the regulated company's capital structure, and CAPM reapplied with this levered beta, which reflects both the business and financial risk of the target company.

Hamada adjustment procedures—so-named for Professor Robert S. Hamada[24] who contributed to their development[25]—are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

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[24] Distinguished professor emeritus of finance and former dean of the University of Chicago's Booth School of Business. Professor Hamada is credited for developing a method to determine the cost of equity for a company with a different capital structure than that of the comparable companies. His research allows us to compare the cost of equity for companies that have different amounts of equity on an apples-to-apples basis.

[25] Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock", *The Journal of Finance*, 27(2), 1971, pp. 435-452.

Exhibit 605 contains confidential information and is subject to

General Protective Order 23-132

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Amber Riter
Shannon Greene

February 29, 2024

Table of Contents

I. Introduction

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

A. My name is Amber M. Riter. I am an Economist and the Lead Load Forecasting Analyst at PGE. My name is Shannon M. Greene. I am an Economist and a Load Forecasting Analyst at PGE. We are responsible for developing PGE's energy deliveries forecast. Our qualifications are provided at the end of our testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present PGE's 2025 test year energy and customer forecast.

Q. What load forecast-related request does PGE make of the Commission in this proceeding?

A. PGE requests the Commission: 1) accept PGE's methodology, including modeling changes described in this testimony; 2) accept, as a preliminary matter, our forecast of energy deliveries, recognizing that updates will be made throughout the course of this proceeding to reflect the latest inputs; and 3) set a schedule in this proceeding allowing for periodic updates of the energy delivery forecast for 2025.

Q. Does PGE intend to update its 2025 forecast during this case?

A. Yes, frequent updates are an important means of managing near-term uncertainty. We intend to update the test year forecast consistent with prior cases. Updates will include model re-estimation to: 1) incorporate more current load and economic data as they become available; 2) refresh forward-looking inputs assumptions and economic outlook; and 3) incorporate the most current operational information in large customers' usage forecasts.

Q. Have there been methodological changes from the prior version of PGE's energy delivery models presented in PGE's most recent general rate case?

A. No significant methodological changes have been made. PGE updated the model inputs, reviewed specifications, re-estimated models, and maintained an automated ARIMA process consistent with that used in the final load forecast in Docket No. UE 416 (UE 416).[1]

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II – Overview and Forecast Summary
- Section III – Methodology
- Section IV – Uncertainty
- Section V – Qualifications

[1] Consistent with UE 416 Second Partial Stipulation https://edocs.puc.state.or.us/efdocs/HAR/ue416har143844.pdf

II. Overview and Forecast Summary

Q. Please describe PGE's delivery forecast.

A. PGE's 2025 test year energy forecast is for energy deliveries of 22,298-gigawatt hours (GWh), on a cycle-month (billing) basis, including deliveries to customers who opted out of PGE's cost-of-service rates for direct access under Schedules 485, 489 and 689. The forecast reflects current expected economic conditions for Oregon in 2024 and 2025, as well as operational changes among PGE's largest customers, savings from incremental energy efficiency (EE) programs that are implemented by the Energy Trust of Oregon (ETO) and forecasted incremental electric vehicle adoption, building electrification and customer-sited solar generation.

Q. How does the 2025 forecast compare to recent historical demand?

A. Table 1, below, summarizes the GWh delivery forecast in annual percentage changes on a weather-adjusted, billing cycle basis from 2020 through 2025. Strong growth in deliveries to industrial customers related to high -tech expansion and new data centers continues to be the primary driver of total energy deliveries growth of 3.2% expected for 2025. This is an acceleration from 2023 and 2024 growth rates, which are depressed somewhat by the closure of a large customer in October of 2023. Electrification loads begin to more than offset decreases due to increased rooftop solar generation in 2025.

Table 1

Change in GWh Delivery from Preceding Year: 2020-2025

Voltage Service Class	2020	2021	2022	2023	2024 (E)	2025 (E)
Residential	4.9%	1.4%	-0.9%	-0.5%	0.6%	1.0%
Commercial	-6.8%	3.5%	0.2%	-0.2%	0.0%	-0.1%
Industrial	6.5%	8.3%	10.3%	7.1%	6.8%	9.2%
Total	0.8%	3.8%	2.4%	1.8%	2.2%	3.2%

Q. What are the key results of PGE's residential forecast?

A. For the 2025 test year, we forecast deliveries of 7,891 GWh to 829,611 residential customers. Residential energy deliveries growth is related both to growth in customer count and changes in average usage. We expect growth in customer count to remain depressed in 2024, consistent with 2023 and begin to recover in 2025. This reflects the lagged effects of slowed population growth and the current interest rate environment's downward pressure on new construction. The forecast for residential customer growth is 0.6% in 2024 and 1.0% in 2025.

Residential average use-per-customer is transitioning from negative towards positive as year-over-year decreases, reflecting long-standing gains in energy efficiency and more recent increases in rooftop solar generation, become increasingly offset by electrification and vehicle charging. In 2025, residential usage per customer is projected to remain flat at 0.0% growth when compared to 2024. The "Connects" tab of PGE Exhibit 701 shows the forecast of building permits, new connects, and customer counts. The "Residential" tab displays the forecast of kWh use per customer and deliveries to residential customers in detail. The residential forecast includes residential outdoor area lighting energy.

Q. What are the key results of PGE's commercial forecast?

A. For the 2025 test year, we forecast deliveries of 7,084 GWh to general service commercial customers, a 0.1% decrease over forecasted 2024 energy deliveries. Energy efficiency offsets the impact of electrification and employment growth on commercial energy deliveries. PGE's Exhibit 701 "Final Forecast" and "Non-Residential" tabs contain the detailed forecast of deliveries to non-residential customers.

Q. What are the key results of PGE's industrial sector forecast?

A. For the 2025 test year, we forecast deliveries of 7,323 GWh to primary and sub-transmission service customers, 9.2% higher than forecasted 2024 deliveries, following growth of 6.8% in 2024. The rate of growth in deliveries to industrial customers slows somewhat in 2023 and 2024 due to the closure of a large paper customer in October of 2023 and a temporary pause in expansion experienced in 2023. However, with projects coming online and ramping upward over the next several years we expect continuation of a strong growth cycle. The "Final Forecast," "Non-Residential," and "Large Customer" tabs of Exhibit 701 show detailed information on this forecast.

Q. What are the key results of PGE's miscellaneous rate schedules forecast?

A. Like prior years and past general rate case filings, deliveries to miscellaneous rate schedules account for a very small portion of total retail deliveries. The "Miscellaneous" tab of PGE Exhibit 701 displays the forecast for miscellaneous schedules, 133 GWh for the 2025 test year.

Q. What is the impact of incremental end use drivers on the energy deliveries forecast?

A. In 2025, the total incremental impact for end use drivers (rooftop solar, transportation electrification and building electrification) is 91 GWh (0.4%). The impact by customer group is shown in the "End Use Impact" tab of PGE Exhibit 701.

III. Forecast Methodology and Input Assumptions

A. Methodology

Q. Please summarize the process you use to develop the retail energy deliveries forecast.

A. PGE's load forecast is based on monthly time-series econometric regression models that estimate the relationship between billing cycle customer count and energy deliveries to multiple explanatory variables, including weather variables, economic variables, historical energy efficiency data and seasonal control variables. The most current forecasted explanatory variables are applied to the coefficients from the regression models to develop the energy deliveries forecast.[2] Historical data is then used to transform this core forecast output - cycle energy deliveries and customer count by rate schedule - into detailed billing determinant information, calendar month forecasts and forecasts of gross demand needed to serve that metered load on an hourly basis.

Q. Please describe the residential forecast models for the 2025 test year.

A. For residential customers, we model both customer counts and usage per customer by segment. Customer count forecasts are developed based on a forecast of new connects by type, single family and multifamily, added to existing customer count. Usage per customer is also modeled by dwelling type - single family, multi family, and manufactured home - as well as total energy deliveries for those customers falling into the 'other dwelling types' category.

Q. Please describe the non-residential forecast models for the 2025 test year.

A. PGE's regression models for non-residential energy deliveries are grouped into five rate-schedule-based models: Schedule 32, Schedule 38, Schedule 83, Schedule 85, and

[2] PGE's load forecasting workpapers present model specifications, input variables and additional information on model specification and results.

Schedule 89. These regression models exclude those customers that are forecasted individually in the large load forecast.

Q. How were the models tested?

A. PGE's model testing procedure remained consistent with that described in prior dockets. For each forecast group, PGE reviews a variety of alternate model specifications. Model residuals are reviewed, confirming that they appear uncorrelated and normally distributed. PGE also reviews regression output statistics, such as the Durbin Watson (DW) statistic, Adjusted R- squared (R^2), and Akaike Information Criterion (AIC). PGE inspects the time series plots to assess model performance and to look for outliers. Final model specifications are reviewed to confirm that significant variables had logical signs and magnitude of coefficients.

Q. How were the ARIMA terms identified?

A. Starting with the September 2023 load forecast PGE began using an automated process to select ARIMA model parameters instead of manually reviewing model output including the model correlogram and Durbin-Watson statistic. Consistent with the rest of PGE's model methodology, PGE developed the automated processes using the EViews software to specify the regression models and the SAS software to estimate forecasts and compile results. The autoarma function in EViews selects ARIMA parameters and the proc.arima function in SAS estimates final forecasts.

Q. How are large customer loads forecasted?

A. PGE's near-term energy deliveries forecast, which extends five years, includes individual customer forecasts for a subset of its customers. These customers tend to be large or rapidly growing; however, smaller customers may be included simply based on legacy of historical loadings that fit these criteria. PGE's process for developing its large customer forecast is based on review of monthly historical data and forecasted economic conditions, quarterly meetings with PGE's key account managers, and assessment of risks associated with load ramping cadence and total anticipated loading which includes considerations of relevant contracts with customers.

Q. How does PGE account for the impact of energy efficiency in its forecast?

A. PGE accounts for energy efficiency by including a time series reflecting historical savings within the regression models as an explanatory variable. Forecasted savings provided by ETO are included to estimate the forecast period.

Q. How does PGE account for the impact of new technologies in its energy deliveries forecast?

A. PGE's energy deliveries forecast accounts for specific end-use technologies using an out-of-model adjustment. This adjustment accounts for the incremental impacts of rooftop solar penetration, electric vehicle charging, and building electrification beyond those already embedded in PGE's energy deliveries as of October 2023 based on forecasts provided by PGE's distributed energy resource planning team.

Q. How do you forecast the gross loads delivered to the PGE system?

A. The process of converting metered energy deliveries to gross loads, reflecting the load that needs to be procured to serve forecasted deliveries at the meter, involves four steps:

1) Aggregated cycle-based rate schedule MWh deliveries are converted into voltage service levels using ratios based on historical data.
2) Cycle-based energy deliveries are converted to calendar-based deliveries using cycle-to-calendar ratios.

3) Transmission and distribution (line) losses are added to deliveries at the meter to obtain the bus bar energy (MWh or MWa) required to meet the aggregated end users' demand.

4) These monthly gross load volumes are fit to a historically-based 8,760 profile to create an hourly output file.

Q. Did you make a separate forecast of delivery to Rate Schedule 485/489/689 customers?

A. Yes. PGE separates the delivery of energy to customers who chose service under Schedule 485/489 (long-term direct access) and Schedule 689 (new load direct access) by 2023 year-end from the energy delivery forecast to customers served under PGE cost-of-service (COS) rates. Schedule 485/489 and Schedule 689 are the only services under which we forecast customers to receive direct access service in 2025. We prorate the COS and Schedule 485/489 deliveries by applying these customers' respective historical shares of rate schedule energy to the forecast. For Schedule 689 and several large customers on Schedule 489, customer loads are forecast individually and can be directly assigned to the appropriate rate. PGE Exhibit 701 tab "COS Direct Access" shows the forecast of deliveries in 2025 to PGE COS customers and direct access (Schedule 485/489/689) customers.

B. Model data

Q. What sources of information do you use to forecast energy deliveries?

A. PGE models are based on historical customer billing and new connects data.[3] Historical weather data is collected from the National Oceanic and Atmospheric Administration's National Weather Service (NOAA's NWS). For historical employment data, PGE uses the

[3] Customer connects, or new service connections, are tracked using PGE's customer billing data. There is a lag in availability of new connects data because the data first appear in billing data when the customer is first billed.

official Oregon series maintained by the Oregon Employment Department. Quarterly savings reports from ETO are used to develop a historical time series of energy efficiency savings.

To estimate the forecast, PGE uses several third-party forecasts as inputs. The forecast of economic drivers comes from the Oregon Department of Administrative Services' Office of Economic Analysis (OEA). Energy efficiency forecasts come from the ETO. Forecasts of load impacts of end-use drivers (rooftop solar, transportation electrification, and building electrification) are provided by PGE's Distributed Resource Planning (DRP) team.

Finally, customers who are large energy users often provide operational information and, if available, forecasts of energy use through correspondence with PGE's Key Customer Managers.

Q. How current are the inputs used for the 2025 test year forecast?

A. The models estimated for use in this proceeding are based on historical data through the October 2024 billing cycle and new connects data through June 2023.[4] OEA's December 2023 economic forecast was used to reflect economic conditions and the ETO provided an updated near-term forecast in November 2023. The end-use driver forecasts were updated in April 2023.

C. Weather Inputs

Q. What assumption did you make regarding weather inputs in the forecast?

A. The test year energy deliveries forecast is based on a modeled normal weather assumption, estimated to capture gradual warming observed in the Portland area over the last 40 years. The model is estimated using historical, monthly degree day data from 1941 to 2022. The structure of the model estimates a linear trend fit beginning in 1975. The aim of this

[4] Connects data is available on a 4-month lag, reflecting the average amount of time it takes for a physical service connection to show up as a billed account in PGE's billing data.

approach is not to capture detailed climate science results or to develop a precise forecast for 2025, but rather to capture an unbiased base case weather-year that is reflective of warming experienced in the region. This methodology was approved by the Commission in Docket No. UE 335. "Degree Days" tab of PGE Exhibit 701 shows the degree days used for 2024 and 2025.

Q. Does PGE plan to revise its approach to estimating normal weather conditions in the future?

A. Yes. PGE's load forecasting team is currently reviewing the application of a methodology presented by Electric Power Research Institute's (EPRI) in the context of its three-year Climate READI (REsilience and ADaptation Initiative) to service area weather data based on climate model analysis performed by Oregon State University's Oregon Climate Change Research Institute. PGE intends to finalize the analysis of using this approach during 2024. In addition, PGE intends to review new data as it becomes available and assess its usefulness as an input in the load forecast.

D. Economic Conditions

Q. What is the base case macroeconomic assumption in the 2025 test year forecast?

A. PGE utilizes two sources for macroeconomic assumptions, S&P Global Market Insights, which provides U.S. and global economic forecasts, and OEA which provides an Oregon economic forecast. Outlooks from both entities can be characterized as a soft-landing scenario, reflecting a continued – but slowed - growth outlook. Oregon non-farm employment growth rates slow from 2.2% in 2023 to 1.0% in 2024 and 0.7% in 2025, reflecting rebalancing in labor markets.

Q. What are the most influential economic drivers included in your forecast?

A. The primary economic drivers in the non-residential energy deliveries models are employment levels. Oregon Total Non-Farm Employment is an explanatory variable in the Rate Schedules 32, 83 and 85 models. Rate Schedule 89, which includes many of PGE's larger customers, includes a segment-specific employment variable reflecting the high-tech industry, computer, and electronic product manufacturing employment.

The residential forecast is linked to economic conditions via the customer count forecast models. PGE new connects are forecasted based on local building permits. As local building permits are not available in our third-party provided forecasts, PGE creates an independent building permits forecast. The main driver of the multi-family building permits forecast is Oregon's construction employment while the main driver of the single-family building permits forecast is total housing starts in Oregon.

IV. Forecast Uncertainty

Q. Is the forecast subject to uncertainty?

A. Yes. The MWh delivery forecast we submit in this filing is our "expected" or mid-point estimate but is subject to uncertainty. As such, it is a 50/50 "point" forecast, with a 50% chance that the actual outcome falls short of or exceeds the forecast. As with any forecast, actual conditions may differ from what we assumed or anticipated in the forecast, resulting in a different outcome.

The accuracy of a forecast depends not only on the model specification but also on the accuracy of the independent variables driving the forecast. In addition, the forecast includes assumptions surrounding key customers' operational decisions, new customers' entry or existing customers' exit, and the absence of further unforeseen natural disasters, pandemics, wars or geopolitical turmoil. The accuracy of our forecast will be impacted by the extent to which actual outcomes of these variables differ from our assumptions.

Q. How do you address uncertainty in your forecast?

A. PGE aims to reduce uncertainty by using the most current information available in our forecast models. PGE's input assumptions, such as employment forecasts, weather data, and actual load, are refreshed in each forecast. PGE tracks forecast performance monthly and updates our forecast multiple times a year to include the most recent historical trends, billing data, and input assumptions available.

Q. How has PGE's load forecast performed compared to industry benchmarks?

A. While forecasts are always subject to uncertainty, PGE's load forecast has performed well over the years. Table 2 displays PGE's year-ahead load forecast variance, compared to industry average performance, measured in mean absolute percentage error (MAPE), as reported in Itron's annual load forecasting benchmark survey. PGE's forecast variance is presented using the actual directional percentage variance, where a negative number reflects weather-adjusted energy deliveries that were lower than forecasted.

Table 2
Comparison of PGE Forecast Error to Itron Benchmark Survey

	2016		2017		2018		2019		2020		2021		2022	
	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE
Residential	1.7%	0.1%	1.4%	-1.3%	1.8%	-0.5%	1.2%	-2.2%	3.8%	4.2%	2.4%	4.2%	1.9%	2.7%
Commercial	1.8%	-2.0%	1.3%	0.3%	2.0%	1.1%	1.7%	-1.0%	6.5%	-7.0%	3.1%	3.0%	2.7%	-1.2%
Industrial	3.3%	-2.7%	2.3%	2.0%	1.9%	0.7%	4.1%	4.8%	8.3%	2.6%	3.1%	5.4%	3.8%	0.5%
System	1.6%	-1.4%	1.1%	0.0%	1.3%	0.4%	1.4%	-0.2%	3.1%	-0.4%	1.7%	4.1%	1.8%	0.8%

V. Qualifications

Q. Ms. Riter, please state your educational background and experience.

A. I received a Master of Arts degree in Economics with a focus on Environmental and Natural Resource Economics from the University of New Mexico. I have been working as an Economist in load forecasting since 2009. Prior to joining PGE in 2014, I worked at PNM Resources, the parent company of Public Service Company of New Mexico (PNM) and Texas New Mexico Power (TNMP), performing load forecasting and load research analysis.

Q. Ms. Greene, please state your educational background and experience.

A. I received my Bachelor of Arts in Economics and Mathematics from the University of Oregon. I have been working as an Economist in energy deliveries forecasting for PGE for the past three years. Prior to joining PGE in 2020, I worked at The Cadmus Group for five years, performing energy efficiency evaluation, focusing on economic modeling and statistical analysis.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibits	**Description**
701	Load Forecasting Tables

Energy Deliveries Forecast (Base[1]) by Service Level

(at average weather)

Base Forecast

	(in GWh)						% Change [2]				
	2020	**2021**	**2022**	**2023**	**2024 (F)**	**2025 (F)**	**2021**	**2022**	**2023**	**2024**	**2025**
Residential	7,764	7,869	7,801	7,765	7,813	7,847	1.4%	-0.9%	-0.5%	0.6%	0.4%
Residential Area Lighting	2	2	2	2	2	2	-3.0%	-1.4%	-1.9%	-0.7%	-1.4%
Total Residential	7,765	7,871	7,802	7,766	7,815	7,848	1.4%	-0.9%	-0.5%	0.6%	0.4%
General Service	6,721	6,944	6,986	6,958	6,945	6,910	3.3%	0.6%	1.6%	-0.2%	-0.5%
Commercial Area Lighting	13	12	12	12	11	11	-6.0%	-3.8%	-2.5%	-0.9%	0.0%
Irrigation Service	70	91	66	82	80	80	30.3%	-28.1%	24.6%	-2.4%	0.2%
Street and Traffic Lighting	52	49.0	46	44	41	40	-5.4%	-6.8%	-4.6%	-5.3%	-2.6%
Commercial, Secondary Voltage Service	6,856	7,097	7,109	7,094	7,077	7,041	3.5%	0.2%	-0.2%	-0.2%	-0.5%
Primary Voltage Service	4,615	4,989	5,526	5,987	6,418	7,035	8.1%	10.8%	8.3%	7.2%	9.6%
Sub-Transmission Voltage Service	293	324	335	292	283	282	10.8%	3.2%	-12.9%	-2.9%	-0.3%
Industrial	4,908	5,314	5,861	6,279	6,701	7,317	8.3%	10.3%	7.1%	6.7%	9.2%
Total	19,529	20,281	20,772	21,140	21,593	22,207	3.8%	2.4%	1.8%	2.1%	2.8%

1) DEC22B_RATE

2) Calculated from rounded numbers

Energy Deliveries Forecast (Final[1]) by Service Level

(at average weather)

Net of Incremental Distributed Energy Resources

	(in GWh)						% Change [2]				
	2020	**2021**	**2022**	**2023**	**2024 (F)**	**2025 (F)**	**2021**	**2022**	**2023**	**2024**	**2025**
Residential	7,764	7,869	7,801	7,765	7,813	7,889	1.4%	-0.9%	-0.5%	0.6%	1.0%
Residential Area Lighting	2	2	2	2	2	2	-3.0%	-1.4%	-1.9%	-0.7%	-1.4%
Total Residential	7,765	7,871	7,802	7,766	7,815	7,891	1.4%	-0.9%	-0.5%	0.6%	1.0%
General Service	6,721	6,944	6,986	6,958	6,959	6,953	3.3%	0.6%	-0.4%	0.0%	-0.1%
Commercial Area Lighting	13	12	12	12	11	11	-6.0%	-3.8%	-2.5%	-0.9%	0.0%
Irrigation Service	70	91	66	82	80	80	30.3%	-28.1%	24.6%	-2.4%	0.2%
Street and Traffic Lighting	52	49	46	44	41	40	-5.4%	-6.8%	-4.6%	-5.3%	-2.6%
Commercial, Secondary Voltage	6,856	7,097	7,109	7,094	7,091	7,084	3.5%	0.2%	-0.2%	0.0%	-0.1%
Primary Voltage Service	4,615	4,989	5,526	5,987	6,420	7,041	8.1%	10.8%	8.3%	7.2%	9.7%
Sub-Transmission Voltage Service	293	324	335	292	283	282	10.8%	3.2%	-12.9%	-2.9%	-0.3%
Indsutrial	4,908	5,314	5,861	6,279	6,703	7,323	8.3%	10.3%	7.1%	6.8%	9.2%
Total	19,529	20,281	20,772	21,140	21,610	22,298	3.8%	2.4%	1.8%	2.2%	3.2%

1) DEC22D_RATE

2) Calculated from rounded numbers

Residential Building Permits, New Connects, Vacancy Rates and Customer Counts

	2020	2021	2022	2023	2024	2025
Building Permits [2]						
Single-Family	10,480	11,717	10,435	9,828	10,256	10,433
Multi-Family	6,932	8,878	9,463	7,448	9,672	9,882
New Connects						
Single-Family	4,561	4,801	4,436	4,357	4,017	4,276
Multi-Family	6,225	4,990	3,880	6,441	4,867	4,393
Mobile Home	119	91	61	55	60	60
Other	276	221	156	90	60	60
Total Residential Connects	11,181	10,103	8,533	10,943	9,004	8,789
Commercial Connects	2,402	2,498	2,195	2,296	2,195	2,216
Total New Connects	13,583	12,601	10,728	13,239	11,199	11,005
Residential Customer Counts						
Single-Family	490,672	494,397	498,573	500,991	503,942	507,792
Multi-Family	263,543	268,812	273,726	278,057	280,426	284,752
Mobile Home	34,911	34,915	34,891	34,722	34,813	34,789
Other	2,028	2,231	2,383	2,158	2,389	2,278
Total Number of Accounts [3]	791,154	800,355	809,573	815,928	821,570	829,611

1) Includes actuals through December 2023, except for connects which include actuals through June 2023

2) Oregon building permits

3) Includes vacant accounts

Residential Use per Customer and Energy Deliveries by Dwelling Type

(at average weather)

Net of Incremental Distributed Energy Resources

	2021	2022	2023	2024 (F)	2025 (F)	2021	2022	2023	2024	2025
Use per Customer (kWh)										
Single-Family Heat	10,980	10,700	10,600	10,626	10,633	5.3%	-2.6%	-0.9%	0.2%	0.1%
Multiple-Family Heat	7,297	7,256	7,118	7,078	7,077	5.7%	-0.6%	-1.9%	-0.6%	0.0%
Mobile Home Heat	13,142	13,098	13,006	13,052	13,097	1.7%	-0.3%	-0.7%	0.3%	0.3%
Other	8,832	9,554	10,856	8,148	8,253	37.8%	8.2%	13.6%	-24.9%	1.3%
Average Use per Customer	9,834	9,638	9,518	9,512	9,511	5.1%	-2.0%	-1.2%	-0.1%	0.0%
Ultimate Deliveries (in GWh)										
Single-Family Heat	5,429	5,335	5,311	5,355	5,400	6.1%	-1.7%	-0.5%	0.8%	0.8%
Multiple-Family Heat	1,962	1,986	1,979	1,985	2,015	7.9%	1.2%	-0.4%	0.3%	1.5%
Mobile Home Heat	459	457	452	454	456	1.7%	-0.4%	-1.2%	0.6%	0.3%
Other	20	23	23	19	19	51.6%	15.6%	2.9%	-16.9%	-3.4%
Schedule 7 Deliveries	7,869	7,801	7,765	7,813	7,889	6.3%	-0.9%	-0.5%	0.6%	1.0%
Residential Lighting	2	2	2	2	2	-15.2%	-1.4%	-1.9%	-0.7%	-1.4%
Total Residential Deliveries	7,871	7,802	7,766	7,815	7,891	6.3%	-0.9%	-0.5%	0.6%	1.0%

Non-Residential Energy Deliveries Forecast by Rate Schedule

(at average weather)

Net of Incremental Distributed Energy Resources, Excluding Large Customers

	(in GWh)						% Change [1]				
	2020	**2021**	**2022**	**2023**	**2024 (F)**	**2025 (F)**	**2021**	**2022**	**2023**	**2024**	**2025**
Schedule 32	1,491	1,527	1,538	1,540	1,553	1,550	2.5%	0.7%	0.1%	0.8%	-0.1%
Schedule 38	26	27	27	26	27	27	6.2%	0.0%	-5.7%	4.5%	0.4%
Schedule 83	2,712	2,829	2,912	2,836	2,860	2,868	4.3%	2.9%	-2.6%	0.8%	0.3%
Schedule 85 [2]	3,226	3,195	3,206	3,227	3,227	3,210	-1.0%	0.4%	0.6%	0.0%	-0.5%
Schedule 89 [2]	312	380	387	432	407	409	21.6%	2.0%	11.7%	-6.0%	0.5%
Total Non-Residential	7,767	7,959	8,072	8,061	8,073	8,064	2.5%	1.4%	-0.1%	0.1%	-0.1%

1) Calculated using rounded-numbers

2) Excluding individually forecasted large customers

Large Customer Deliveries Forecast by Rate Schedule

	(in GWh)						% Change [1]				
	2020	**2021**	**2022**	**2023**	**2024 (F)**	**2025 (F)**	**2021**	**2022**	**2023**	**2024**	**2025**
Schedule 85	249	215	192	205	230	276	-13.6%	-10.9%	6.6%	12.2%	20.1%
Schedule 89	1,343	1,542	1,847	2,138	1,968	2,251	14.8%	19.8%	15.8%	-8.0%	14.4%
Schedule 90	2,270	2,543	2,736	2,833	3,392	3,685	12.0%	7.6%	3.5%	19.7%	8.7%
Total Large Customer	3,862	4,300	4,775	5,175	5,589	6,212	11.3%	11.1%	8.4%	8.0%	11.2%

1) Calculated using rounded-numbers

Forecast of Energy Deliveries to Miscellaneous Rate Schedules

	(in GWh)						% Change [1]				
	2020	**2021**	**2022**	**2023**	**2024 (F)**	**2025 (F)**	**2021**	**2022**	**2023**	**2024**	**2025**
Residential											
Outdoor Area Lighting [2]	1.7	1.7	1.7	1.6	1.6	1.6	-3.0%	-1.4%	-1.9%	-0.7%	-1.4%
Commercial											
Outdoor Area Lighting [3]	13.1	12.4	11.9	11.6	11.5	11.5	-6.0%	-3.8%	-2.5%	-0.9%	0.0%
Farm Irrigation et al. [4]	70.0	91.2	65.5	81.6	79.7	79.9	30.3%	-28.1%	24.6%	-2.4%	0.2%
Street and Other Lighting [5]	51.8	49.0	45.7	43.5	41.2	40.2	-5.4%	-6.8%	-4.6%	-5.3%	-2.6%
All Miscellaneous Schedules	137	154	125	138	134	133	12.8%	-19.1%	11.0%	-3.2%	-0.7%

1) Calculated from rounded numbers

2) Schedule 15R

3) Schedule 15C

4) Schedules 47 & 49

5) Schedules 91, 92, 95

Total Deliveries and Peak Demand

	GWh [1]	Average MW [2]	Peak MW [3]
2016	19,651	2,287	3,726
2017	19,147	2,389	3,976
2018	19,221	2,322	3,816
2019	19,344	2,343	3,765
2020	19,368	2,348	3,771
2021	19,529	2,464	4,453
2022	20,772	2,551	4,255
2023	21,140	2,562	4,498
2024 (F)	21,610	2,623	4,129
2025 (F)	22,298	2,705	4,240

1) Cycle basis, at the meter, actual through 2023, weather normalized.

2) Calendar basis, at the bus bar, actual through 2023, not adjusted for weather.

3) Coincidental annual system peak at bus bar; includes actual through 2023, not adjusted for weather.

Forecast of 2025 Deliveries to Cost of Service and Direct Access Customers

Net of Incremental Distributed Energy Resources

(in GWh)

	Cost of Service [1]	Direct Access [2]	Total Deliveries [3]
Residential	7,891	0	7,891
Secondary	6,611	433	7,044
Primary	5,384	1,657	7,041
Sub-Transmission	33	250	282
Lighting	40	0	40
Total Retail [2]	19,958	2,340	22,298

1) Includes economic replacement VPO deliveries

2) Schedule 485/489/689 deliveries

3) Totals may not add due to rounding.

Degree Day Variables

	2024		2025	
	HDD65	CDD65	HDD65	CDD65
January	764	-	763	-
February	644	-	643	-
March	560	-	559	-
April	409	0	408	0
May	256	10	254	10
June	123	40	122	41
July	40	136	39	137
August	10	243	10	246
September	23	182	23	184
October	116	41	115	42
November	340	1	339	1
December	658	-	657	-
Annual	3,943	653	3,931	660

Comparison of PGE Forecast Error to Itron Benchmarking Survey

	2011		2012		2013		2014		2015		2016		2017	
	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE
Residential	1.7%	-0.5%	1.5%	0.0%	1.7%	0.3%	1.5%	1.2%	1.9%	1.5%	1.7%	0.1%	1.4%	-1.3%
Commercial	1.7%	-0.4%	2.0%	-1.4%	2.1%	-1.9%	1.3%	0.6%	1.6%	0.8%	1.8%	-2.0%	1.3%	0.3%
Industrial	3.2%	-0.7%	3.2%	-4.5%	4.4%	-8.8%	3.4%	-0.5%	3.0%	2.8%	3.3%	-2.7%	2.3%	2.0%
System	NA	-0.5%	1.6%	-1.5%	1.5%	-2.5%	1.3%	0.6%	1.9%	1.5%	1.6%	-1.4%	1.1%	0.0%

2018		2019		2020		2021		2022	
Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE
1.8%	-0.5%	1.2%	-2.2%	3.8%	4.2%	2.4%	4.2%	1.9%	2.7%
2.0%	1.1%	1.7%	-1.0%	6.5%	-7.0%	3.1%	3.0%	2.7%	-1.2%
1.9%	0.7%	4.1%	4.8%	8.3%	2.6%	3.1%	5.4%	3.8%	0.5%
1.3%	0.4%	1.4%	-0.2%	3.1%	-0.4%	1.7%	4.1%	1.8%	0.8%

Energy Efficiency Forecast

						% Change [1]				
	2021	2022	2023 [2]	2024 [3]	2025 [3]	2021	2022	2023 [2]	2024 [3]	2025 [3]
Residential EE Savings	87	94	99	103	108	9.3%	8.1%	5.8%	4.4%	4.5%
Commercial EE Savings	110	118	126	134	142	8.2%	7.4%	6.4%	6.4%	6.3%
Indutrial EE Savings	83	91	100	107	114	8.5%	10.3%	9.8%	7.2%	6.6%
Total EE Savings	279	303	325	344	365	8.6%	8.5%	7.2%	6.0%	5.9%

1) Calculated using rounded-numbers

2) Calculated using quarterly actuals through Q2 2023

3) ETO forecast provided in November 2023

Distributed Energy Resources

Annual Incremental Forecast (in GWh)

	2024	2025
Building Electricification	21.9	66.0
Transportation Electricification	50.8	147.9
Storage	0.1	0.3
Solar	(56.2)	(122.8)
Total Residential Impact	0.4	42.3
Total Commercial Impact	16.1	49.0
Total Impact	16.5	91.4

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Robert Macfarlane
Casey Manley

February 29, 2024

Table of Contents

I. Introduction

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

A. My name is Robert Macfarlane. I am Manager, Pricing and Tariffs at Portland General Electric Company (PGE). I am responsible, along with Ms. Manley, for the development of the marginal cost studies.

My name is Casey Manley. I am a Senior Regulatory Analyst in Pricing and Tariffs at PGE. I am also responsible for the development of the marginal cost studies.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony describes the methodologies and results of PGE's updated generation and customer marginal cost of service studies. We continue to use the transmission and distribution marginal cost of service studies from our last general rate case (GRC), Docket No. UE 416 (UE 416) as these cost studies are roughly a year old and as the assumptions remain relevant any updates would not materially change allocations to the various customer classes. PGE Exhibit 801 provides a summary of marginal costs of service by component. Specifically, PGE Exhibit 801 provides the costs by rate schedule for generation capacity and energy, transmission, subtransmission, substation, feeder backbone and tapline, transformers, service laterals, meters, and customer service costs. Rate schedule changes are also discussed in PGE Exhibit 900.

Q. What is the purpose of marginal cost of service studies?

A. The purpose of marginal cost of service studies is to calculate the incremental or marginal unit cost of service for various categories (e.g., energy, distribution substations, feeders, billing). These unit costs, expressed as costs per customer, costs per kilowatt (kW) of demand, or costs per kilowatt hour (kWh) are then used to allocate the functional revenue requirements as described in PGE Exhibit 801.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II – Generation Marginal Cost Study
- Section III – Customer Marginal Cost Study
- Section IV – Area and Streetlights
- Section V – Qualifications

II. Generation Marginal Cost Study

Q. What methodology do you propose for estimating generation marginal costs in this docket?

A. For generation, we propose a long-run methodology that explicitly estimates the cost of long-run marginal generation capacity and long-run marginal energy, reflective of future resources that are non-emitting and future Mid-Columbia (Mid-C) market prices of energy. More specifically, we calculate the net levelized cost for wind, solar, and storage resources.

While the specific resources used in this analysis do not encompass the broader approach PGE will utilize to meet future customer demand (e.g., energy efficiency, demand response, community and customer-sited solar) a study based on utility scale wind, solar, market energy and battery storage is an appropriate proxy for cost allocation purposes at this time. By considering these proxy resources the complexity caused by a transitioning generation and capacity landscape is avoided while also providing results that reasonably approximate those from legacy generation marginal cost studies. In addition, this relative consistency among proxy resources with the methodology applied in recent studies is important to maintain price impact stability among customer classes and prevent sharp or abrupt shifts resulting from more extreme changes in methodology.

Q. How is the methodology used in this proceeding to develop the long-run generation allocation different from that applied in UE 416?

A. The UE 416 methodology to calculate long-run marginal generation cost allocation used wind as the sole resource to estimate the marginal cost of energy and continued the assumption that 100% of its value is energy-related. Utility-scale battery storage was used to estimate marginal generation capacity costs.

The current methodology adds additional sophistication to the calculation of marginal generation cost of energy and capacity. PGE agreed with parties in UE 416 to include in this testimony an analysis and estimates of any marginal cost of capacity offsets attributable to the capacity resource's ability to provide ancillary services, market price arbitrage, and any other benefits that such capacity resource makes available in addition to helping meet net load requirements.

The long-run generation calculation included in this updated study includes solar in addition to wind to estimate the marginal cost of energy, weighted 75% wind and 25% solar in accordance with the preferred portfolio in PGE's recently acknowledged 2023 Integrated Resource Plan (IRP).[1] In addition, the following are incorporated:

- Transmission deferral and integration costs (weighted by nameplate capacity and capacity factor) are added to wind and solar energy costs.
- Integration costs are included to account for ancillary services.
- Transmission costs are also included as a key component for many renewable resources which may be sited in areas more optimal for wind or solar generation.
- The land lease value is subtracted from the wind energy cost. Additionally, the proposed methodology adds the cost to buy energy off the market when solar and wind do not generate enough energy to meet load requirements.

Q. How is the percentage of marginal energy purchased calculated?

A. The percentage of marginal energy purchased is calculated as forecasted market purchases divided by total system load (in MWh). The forecasted average market energy prices are

[1] Docket No. LC 80, PGE 2023 Integrated Resource Plan (IRP) and Clean Energy Plan (CEP) (Mar 31, 2023).

calculated using 2025 Mid-C on and off-peak prices shaped by PGE's historical loss of load by hour.

Q. Does the marginal generation cost of capacity include utility-scale battery storage?

A. Yes. The marginal generation cost of capacity includes utility-scale battery storage net of the flexibility and energy values of the battery and net of the capacity contribution of wind and solar. PGE defines flexibility value as the benefits provided by resources that help meet the system's flexibility adequacy target. The battery's energy value accounts for the market price arbitrage value of the battery. PGE assumes that 3% of its value is energy-related, 5% of its value is flexibility related and 92% is capacity related.

Q. What are the sources of the overnight capital costs for the resources used in the model?

A. The proxy long-run energy resources are Clearwater wind and Mead, Nevada solar facilities. The proxy capacity resource is a generic 4-hour utility-scale battery. Overnight capital costs, as well as operation and management (O&M) expenses, are sourced from the NREL's Electricity Annual Technology Baseline (ATB) Data.[2]

Q. Did you include production tax credits or investment tax credits in your analysis?

A. Yes. With the passage of the federal Inflation Reduction Act in 2022, 100% of available production tax credits are assumed for the first ten years of the wind and solar resources and a one-time investment tax credit of 30% is applied to the first-year costs of the battery resource.

Q. What is the fully allocated cost of each proxy resource?

A. The cost of the battery resource is estimated at $274.78 per kilowatt year (kW-yr) in real levelized 2025 dollars. The flexibility and energy value of the battery resource is estimated at

[2] "Electricity Annual Technology Baseline Data Download," NREL (2023), https://atb.nrel.gov/electricity/2023/data

\$22.24 per kilowatt year (kW-yr) in real levelized 2025 dollars. The weighted wind and solar capacity contribution equal is estimated at \$15.18 per kW-yr in real levelized 2025 dollars. The net generation marginal cost of capacity is estimated at \$237.36 per kW-yr in real levelized 2025 dollars.

The weighted cost of the wind resource, inclusive of fixed transmission costs required to bring the energy to PGE's system and net of integration costs, is estimated at \$62.79 per megawatt hour (MWh) in real levelized 2025 dollars. The weighted cost of the solar resource, inclusive of fixed transmission costs required to bring the energy to PGE's system and net of integration costs, is estimated at \$41.84 per MWh in real levelized 2025 dollars. The weighted cost of the market energy is estimated at \$7.61 per MWh in real levelized 2025 dollars. The net generation marginal cost of energy is estimated at \$112.23 per MWh in real levelized 2025 dollars.

Q. How do you estimate each rate schedule's marginal cost of capacity?

A. To estimate each rate schedule's marginal cost of capacity, we multiply each rate schedule's forecasted monthly coincident peak (i.e., usage during the hour of PGE's system peak) by the fully allocated cost of the battery resource.

Q. How do you estimate each rate schedule's long-run marginal cost of energy?

A. To estimate each rate schedule's marginal cost of energy, we multiply each rate schedule's monthly on-peak and off-peak load forecast by the corresponding monthly on-peak and off-peak long-term energy value.

Q. How do you shape the annual long-run marginal cost of energy into monthly on-peak and off-peak values?

A. The annual long-run marginal energy cost is shaped into monthly on-peak and off-peak values based on the monthly on-peak and off-peak Mid-Columbia forward prices used in PGE's net variable power cost model (i.e., the Multi-area Optimization Network Energy Transaction model, also known as MONET[3]).

[3] *See* PGE's 2025 Annual Update Tariff filing under Docket No. UE 436, Exhibit 100, Section II, for a description of the MONET model.

III. Customer Marginal Cost Study

Q. Are there methodological changes to the customer marginal cost study in this case relative to PGE's recent 2024 GRC?

A. Yes. We have made two improvements to the customer marginal cost study methodology applied in this case. First, customer costs not included in the final 2024 customer marginal cost study but unbundled to the customer category are included for the 2025 unbundled revenue requirement. Second, we analyzed the departments and costs included to ensure they were being allocated to the appropriate customers. After completing this analysis, we refined allocation methodologies for a few cost centers to better align them with the customers that are being served. Column (I) on page 3 of PGE Exhibit 801 summarizes marginal customer costs.

Q. Why is PGE proposing these changes?

A. In our last general rate case, UE 416, PGE agreed to make changes in its next general rate case after taking time to comprehensively analyze the various departments and functions that serve customers. As described in the response above, we have completed analysis of the customer marginal cost study and unbundled customer costs and have made changes as described later in this testimony.

Q. Please give an overview of the specific changes.

A. Specifically, we have added eight departments to the "Other" consumer category and allocated them in the manner described in the table below. Departments 532, 533, 538, 544, 542, and 547 were proposed for inclusion by the Alliance of Western Energy Consumers

(AWEC) in UE 416.[4] After reviewing these departments, we find that they should be included in the customer marginal cost study and allocated them in accordance with the primary customer classes they serve. Table 1 shows all accounts and departments that have been added to the customer marginal cost study in the "Other" category and how they are allocated.

Table 1
New Departments Included in the 2025 Customer Marginal Cost Study

Account	Department	Description	Allocation Methodology
9030001, 9080001	536	Customer Analytics	Number of customers less lighting customers
9080001	495	Energy Efficiency Outreach	44% to Sch 7 56% to Schedules 32, 38, and 83, based on customer counts
9080001	532	Product Portfolio Management	Number of customers up to 200 kW
9080001	533	Product Development	50% to residential, 50% to non-residential, spread by customer count, excluding lighting, Schedule 38, and irrigation
9080001	538	Flexible Load Product Portfolio	65% residential, 35% non-residential, spread by load, excluding lighting.
9080001	542	Transportation Electrification	60% residential, 40% non-residential, spread by customer count, excluding lighting, irrigation, and Schedule 90.
9080001	544	Growth and Commercialization	Suballocation of RCs reporting to the Director of Customer Solutions.
9080001	546	General Business Segment	5% to Schedule 32, 77% to 95% to Schedules 83 and 85, allocated based on customer count.
9080001	547	Commercial Energy Offerings	33% to Schedule 32, 77% to the remainder of non-residential customers spread by customer count, excluding lighting.
9080001	575	Interconnection Services	65% to residential, 35% to nonresidential, spread by load, excluding Schedule 90
9080001, 9090001	584	Brand Marketing	70% to residential, 30% to nonresidential customers spread by customer count

In addition to the inclusion of these new departments, we removed department 453 (Community Offices) as all community offices have closed and there are no expenses associated with this department in 2025.

[4] Docket No. UE 416, AWEC 300.

Q. Please explain how you determined the allocators for these departments.

A. When deciding how to allocate the new departments within the customer marginal cost study, we considered the primary purpose of each department and spoke with department management and other members of the team to determine which customers were primarily served by a given department and how much of the team's time was spent with various customers. Often a percentage allocator is used paired with customer counts or a subset of customer counts. We find customer counts to be a good proxy of the time that these departments spend with various customer classes because as rate schedules increase, the energy usage of the customer increases and the customer count decreases, which tends to be indicative of program participation and time spent on work for these customers. Explanations on the specific allocations and how we arrived at those allocations follows.

- Department 536, Customer Analytics: This group is responsible for customer analytic work that spans the entire customer base. Due to the volume of residential customers, this team spends a large amount of their time working with residential customer data, which is why customer counts without lighting was selected. Lighting analytics are primarily conducted by different groups within the company, which is why it is appropriate to exclude these customers in this instance. For this department, the greater the number of customers, the more likely it is that a substantial part of their time is being spent working with that customer data.
- Department 495, Energy Efficiency Outreach: This team is responsible for working with residential and small and medium commercial customers, facilitating participation in Energy Trust energy efficiency programs. Within this team, approximately 44% of employees time is spent working on residential-facing

initiatives, while the 56% of employee time is spent with Schedule 32 and Schedule 83 customers, in roughly proportional amounts to the number of customers. Accordingly, we allocate 44% of these costs to residential with the remaining 56% allocated by customer count to Schedule 32 and Schedule 83 customers.

- Department 532, Product Portfolio Development: This team focuses on programs that pertain primarily to residential customers. This team also does some work in the multi-family space which encompasses some small commercial customers. As a result, the number of customers up to 200 kW was selected as the allocator. This directs a large portion of the costs to residential customers, which is the primary focus of this team's program designs, but also directs a smaller portion of the costs to small commercial customers who may own and operate multi-family properties. Lighting customers are not eligible for these programs, so they are excluded from the allocation.
- Department 533, Product Development: This team focuses primarily on batteries and non-emitting grid support resources and their work spans across both residential and commercial customers. While Schedules 38, 47, and 49 customers are eligible for a number of these programs, we are not aware of any current participants and there are no current plans to increase enrollment from these customers. Therefore, these customers, along with lighting customers (who are not eligible) are excluded from the allocation methodology. This team spends 50% of their time on residential customers with the other 50% spent on commercial, allocated by customer count as this is the best proxy for the time spent by rate schedule.

- Department 538, Flexible Load Product Portfolio: This team is responsible for the implementation and ongoing operations of flexible load products and programs for both residential and commercial customers. This team spends 65% of their time on residential customers, with the remaining 35% spent on commercial customers, which we have sub-allocated based on load as many of our commercial demand response programs are based on load reduction. Lighting is excluded as they are not eligible for these programs.
- Department 542, Transportation Electrification: This department is responsible for the design and implementation of Transportation Electrification (TE) pilots and programs including transitioning programs to rates and tariffs, as well as development of the TE plan. The work that this group does spans both residential and commercial customers, with 60% of their time spent on residential customers and the other 40% spent on commercial customers, which we sub-allocated based on customer count as TE programs tend to be more prevalent among the smaller commercial rate schedules which have greater customer counts. We excluded Schedule 90 as no customers on this rate schedule participate in TE programs and we do not anticipate participation soon. Lighting is excluded as these customers are not eligible for TE programs.
- Department 544, Growth and Commercialization: This department contains the administrative costs associated with the programs that the director of customer solutions oversees. As such, the allocator for this department is the suballocation of all departments that report to this director.

- Department 546, General Business Segment: This group works primarily with large commercial customers, though they do work with some small commercial customers. The primary focus of the group is outreach to facilitate non-managed customer participation in PGE programs. Given this split and the work that this team does, a split of 5% to Schedule 32, with the remainder split between Schedules 83 and 85 customers by count is the most appropriate.
- Department 547, Commercial Energy Offerings: The work this team does is focused on product and program development and design for commercial and industrial customers. Approximately one-third of their time is spent on work relevant to Schedule 32 customers with the remaining two-thirds spent on work relevant to the other commercial and industrial rate schedules, which is sub-allocated based on customer count.
- Department 575, Interconnection Services: Department 575 is primarily responsible for net metering applications (NEM), Qualified Facilities (QF), and large generator interconnection. This team spends 65% of their time on residential customer facing work, with the remaining 35% spent on commercial customers, which is being suballocated based on load, excluding Schedule 90 as there is no interconnection work with any customer currently on Schedule 90. Load is a more appropriate allocator in this instance as opposed to customer count as larger customers tend to have more complex interconnection requests or are more likely to have a QF.
- Department 584, Brand Marketing: Brand Marketing is comprised of three teams that manage residential customer marketing, business customer marketing, and brand marketing. In aggregate, 70% of their time is spent related to residential customers

and the remaining 30% is commercial. We suballocate 30% to commercial customers based on customer count as communication to small commercial customers tends to be more frequent than communication to larger commercial customers.

Q. Do you make any other changes?

A. Yes, upon full consideration of the allocators used in the "Other" category of the cost study, we are adjusting the following allocators:

- We adjust the allocator for account 903, department 472 (OPS Performance Solutions) from number of customers to a suballocation of departments related to the customer contact center as department 472 provides support for these groups rather than directly to customers.
- We adjust the allocator for department 924 (Customer Specialized Programs) from number of customers participating in programs to number of large commercial and industrial customers. The expenses charged to the 908 account for department 924 pertain to prospecting new participants for the Dispatchable Standby Generation program, which are customers with demand greater than 250 kW.
- We update the allocation methodology of department 526 (Customer Experience) from customers less than 200 kW of demand to all customers excluding lighting. We modify the allocation for this department because its scope is evolving to serve all customers, with focus on residential and small commercial customers.
- We update the allocator for account 908, department 576 (Transmission & Interconnection) from number of customers participating in programs to number of large non-residential customers. This allocator update better reflects the function and

activities of this department as this department primarily serves Electricity Service Suppliers who want interconnection to our system.

- Finally, account 908, department 927 (Customer Insights) adjusts from number of customers excluding lighting customers to all customer usage excluding lighting and managed customers. Customer Insights is responsible for measuring customer attitudes, behaviors, and opinions to better understand their needs and preferences. This work encompasses all customer classes except managed customers, which is conducted by the Key Customer Team.

Beyond these changes, we do not make any changes to the metering or billing components of the customer marginal cost study at this time. The functions of the departments that comprise these categories has not materially changed.

IV. Area Lights and Streetlights

Q. Please describe how you price Area Lights and Streetlights.

A. We price the investment portion (i.e., poles and luminaires) of providing lighting service using a real levelized annual revenue requirement. Lighting schedule prices are updated to reflect the cost of capital adopted by the Commission in this proceeding.

Q. Please describe how you calculate the amount of outdoor lighting maintenance.

A. We base the test period lighting maintenance amount on the incurred maintenance amounts and the ratio of Light-Emitting Diodes (LEDs) to non-LEDs in the last five years (2019 to 2023). We express the historical maintenance amounts on a per light basis and then escalate this per-light maintenance figure for inflation. A reduction is made for LED area lights and streetlights since their maintenance is significantly less than non-LED lights. We then allocate maintenance costs to each type of luminaire based on the marginal cost of the maintenance study.

Q. Do you provide a summary of the proposed pole and luminaire prices?

A. Yes. This summary is provided in PGE Exhibit 900.

V. Qualifications

Q. Mr. Macfarlane, please state your educational background and experience.

A. I received a Bachelor of Arts business degree from Portland State University with a focus in Finance. I have been Manager, Pricing and Tariffs since September of 2019. My prior title was Regulatory Consultant. Since joining PGE in 2008, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have included pricing, revenue requirement, Public Utility Regulatory Policies Act avoided costs, and regulatory issues. From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, Oregon, where I developed, prepared, and reviewed financial analyses used in securities litigation.

Q. Ms. Manley, please state your educational background and experience.

A. I received a Bachelor of Business Administration degree from University of Portland with a focus in Operations & Technology Management. I have been a Senior Regulatory Analyst since August of 2022. I joined PGE in 2016 and I have worked in the Supply Chain Department, as the Commercial Credit Card Analyst, and as an analyst in Rates and Regulatory Affairs since 2018. Since joining Rates and Regulatory Affairs in 2018, my areas of focus have included revenue requirement, pricing of supplemental schedules, operational tariffs for our customer-facing products and programs, and other regulatory issues.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Pricing and Tariffs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Robert Macfarlane
Christopher Pleasant

February 29, 2024

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Robert Macfarlane. I am Manager of Pricing and Tariffs at Portland General Electric Company (PGE). My qualifications are included in PGE Exhibit 800.

My name is Christopher Pleasant. I am a Regulatory Consultant in Pricing and Tariffs at PGE. My qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony and accompanying exhibits demonstrate how the proposed E-19 Tariff charges in Exhibit 901 recover PGE's 2025 revenue requirement reflective of fair, just, and reasonable prices for our customers.

Q. Please summarize the projected Cost of Service (COS) rate impacts resulting from the proposed allocations.

A. Table 1 below summarizes the impacts for the major rate schedules and the overall COS and Direct Access (DA) impact. Column A includes changes to the revenue requirement in this case, including the Constable Battery Project, which we currently expect to come online prior to January 1, 2025, an inclusive of the 2025 net variable power costs proposed under Docket UE 436 and estimated changes in supplemental schedules currently known and measurable. Column B shows the incremental impacts associated with the Seaside Battery Project, which PGE proposes to include in rates during 2025, and the Investment Tax Credits (ITC) to be included in Schedule 105, expected in June 2025. Column C shows the rate adjustment associated with items indicated in Columns A and B.

Table 1
Estimated Cost of Service Impacts Inclusive of Proposed Base Rates
and Changes to Schedules 105, 122, 123, 125, 126, and 131 (all other supplementals at current prices)[1]

Schedule	A January 2025	B June 2025 (Seaside)	C January and June 2025 Combined
Schedule 7 Residential	7.2%	-0.1%	7.1%
Schedule 32 Small Nonresidential	9.4%	-0.1%	9.3%
Schedule 83 31-200 kW	9.5%	-0.1%	9.4%
Schedule 85 201-4,000 kW	7.2%	-0.1%	7.1%
Schedule 89 Over 4,000 kW	7.4%	-0.2%	7.2%
Schedule 90 Over 30 MWa	4.2%	-0.2%	4.0%
COS & DA Overall	7.4%	-0.1%	7.3%

Q. Is PGE presenting impacts of the proposed prices differently than in previous GRCs?

A. Yes, to better reflect more holistic customer price impacts, PGE Exhibit 902 presents price impacts inclusive of supplemental schedule prices excluding the Public Purpose Charge (PPC) and Low-Income Assistance (LIA). Only known and measurable changes to supplemental schedule prices are incorporated into the impacts presented in PGE Exhibit 902.

Q. Please discuss the tables presented in PGE Exhibit 902.

A. PGE Exhibit 902 contains more detailed information on rate impacts for individual schedules. Table 1 of PGE Exhibit 902 shows the impacts based on proposed prices for base rates plus known and measurable supplemental schedules effective January 1, 2025. These impacts reflect the Unbundled Revenue Requirement, Constable Battery Project, and 2025 net variable power costs forecast under Docket No. UE 436. Other supplemental schedules are included at current prices.

[1] The following schedules are set to zero on January 1, 2025: 122 Renewable Resources Automatic Adjustment Clause, 123 Decoupling, 125 Annual Power Cost Update, 126 Annual Power Cost Variance Mechanism, and 131 Oregon Commercial Activities Tax Recovery. Schedule 105 Regulatory Adjustments changes include the ITC credit that will take effect in approximately June 2025 consistent with the recovery of Constable and Seaside.

Table 2 of PGE Exhibit 902 contains the base rate impacts of the proposed prices, plus known and measurable supplemental schedules effective in June 2025. These impacts include the Seaside Battery project and associated ITCs in addition to the Unbundled Revenue Requirement, Constable Battery Project, and 2025 net variable power costs mentioned above.

The difference between PGE Exhibit 902 Tables 1 and 2 represents the inclusion of the Seaside Battery project with associated ITC amortization. The isolated impact of the Seaside Battery project including the associated ITC amortization is depicted in Table 3 of PGE Exhibit 902.

Q. Please provide an overview of your testimony.

A. In addition to estimating the overall rate adjustments by customer class, our testimony describes the revenue requirement allocation process (i.e., rate spread) and the rate design. We further discuss:

1) Schedule 50 Retail Electric Vehicle Charging Rates moving to base rates.
2) Changes to Schedule 150 Transportation Electrification Cost Recovery due to Schedule 50 moving to base rates.
3) How PGE will refund the value of the ITCs from the Constable and Seaside projects to customers through Schedule 105 when the Seaside battery project comes online.
4) A summary of the updates to prices contained in Schedule 300, Charges as Defined by the Rules and Regulations and Miscellaneous Charges.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II – UE 416 Stipulations
- Section III – Rate Spread

- Section IV – Rate Schedule Design
- Section V – Other Rate Schedule Changes
- Section VI – Qualifications

II. UE 416 Stipulations

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

A. The purpose of this portion of our testimony is to address topics as agreed to in the Fourth Partial Stipulation in PGE's last general rate case (GRC), Docket No. UE 416 (UE 416), approved in Order No. 23-386. More specifically, the stipulation directs PGE to do two things: 1) discuss the time of use (TOU) pricing for large non-residential customers and, 2) to provide an evaluation showing the effects of eliminating the residential block rates on customer usage. Our response to both commitments are provided below.

Q. What did the Fourth Partial Stipulation in UE 416 direct PGE to address regarding TOU pricing for commercial customers on Schedules 83, 85, 89 and 90?

A. The stipulation directs PGE to hold a workshop and examine restructuring the on- and off-peak windows for Schedules 83, 85, 89 and 90 to better reflect system costs. In the stipulation, it was agreed that PGE will either make a proposal to update these rates or justify why the current time structures are appropriate in our next GRC opening testimony.

Q. Is PGE proposing to restructure the peak windows for large non-residential schedules in this proceeding?

A. Yes, PGE is proposing to restructure the on-peak windows for Schedules 38, 83, 85 and 89. The latter three are standard, cost of service schedules delimited by customer size. Schedule 38 is an optional rate available to customers eligible for Schedule 83 (31-200 kW), and stand-alone EV charging service points eligible for Schedules 83 or 85 (201-4,000 kW). Schedule 38 is typically preferable for customers with very peaky loads (i.e., high demand relative to energy use) as it does not include a demand-based price component.

Q. How does PGE propose to restructure the on-peak windows for Schedules 38, 83, 85 and 89 in this proceeding?

A. PGE proposes to align the windows of Schedule 38 with those of Schedules 83, 85 and 89 and to bifurcate the current on-peak window with the creation of a new mid-peak window during daytime hours during the week and on Saturdays.

The current on-peak window for Schedule 38 is:

- Monday through Friday, 7 a.m. to 8 p.m.; all remaining hours are off-peak.

The current on-peak window for Schedules 83, 85 and 89 are:

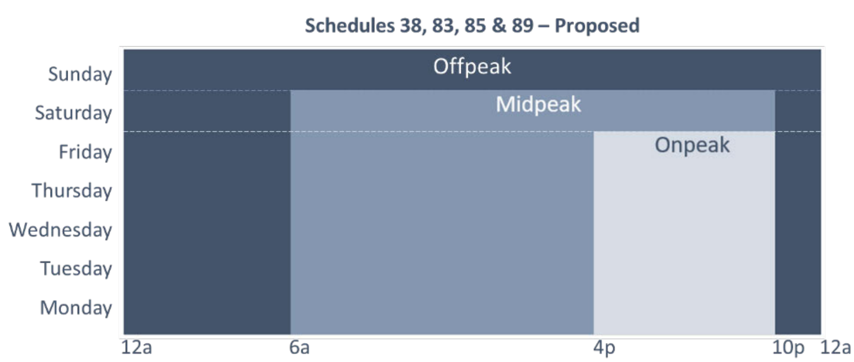
- Monday through Saturday, 6 a.m. to 10 p.m.; all remaining hours are off-peak.

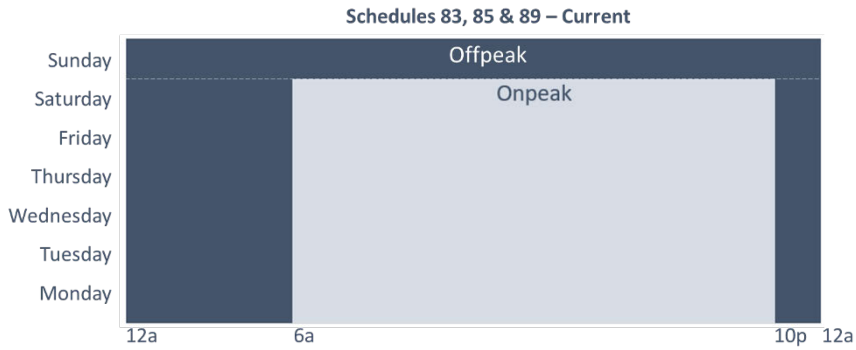
The proposed structure for energy charges is:

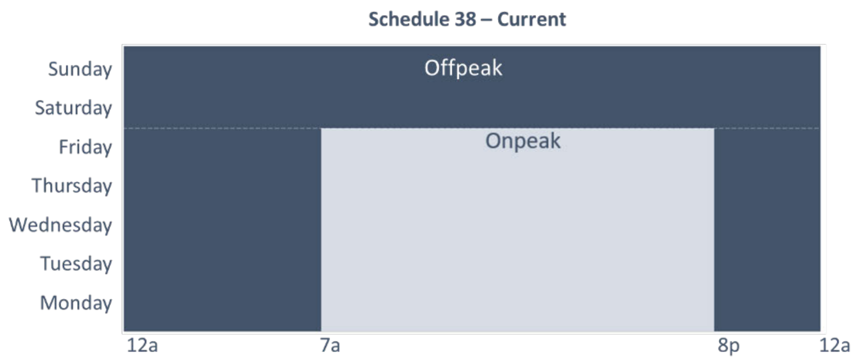
- On-peak: Monday through Friday, 4 p.m. to 10 p.m.
- Mid-peak: Monday through Friday 6 a.m. to 4 p.m. and Saturday 6 a.m. – 10 p.m.
- Off-peak: Monday through Saturday, 10 p.m. – 6 a.m., and all hours on Sundays.

Figure 1 illustrates the proposed time periods as compared to the current periods for large commercial rate schedules.

Figure 1
Time-of-Use Windows for Large Nonresidential Schedules







Q. What data and design elements did PGE consider in development of this proposed structure?

A. In developing the proposed structure, PGE considered modeled system constraints, historical Mid-Columbia (Mid-C) power prices, hourly system load values, and hourly aggregate load values for each rate schedule. A loss of load probability (LOLP) measures the probability that demand will exceed capacity during a given period. The LOLP output from PGE's Integrated Resource Planning (IRP) model indicates the most resource-constrained hours occur during summer evenings, with daytime hours during both the summer and winter following close behind. Within PGE's proposal, 57% of the most resource constrained periods occur within the on-peak window, 35% in the mid-peak period, and 8% in the off-peak period. Historical hourly Mid-C data similarly demonstrates more frequent high prices during summer evening hours.

Another key consideration is accommodating customer rate migration among the large nonresidential cost-of-service schedules and between cost-of-service and daily pricing versions of individual schedules. To ensure smooth transitions between schedules, PGE is proposing a consistent TOU structure across Schedules 38, 83, 85 and 89. Daily market prices are differentiated by the North American Electric Reliability Corporation (NERC) into heavy load and light load hours. NERC heavy load hours align with the current on-peak window as well as the proposed on-peak/mid-peak windows. Maintaining this alignment simplifies pricing for customers as they move between cost-of-service and daily pricing options.

Q. Is this new TOU structure proposed for Schedule 90?

A. No. Schedule 90 is for PGE customers with the largest and most constant load. The aggregate annual load factor for Schedule 90 is 84%, with monthly load factors in the 90-100% range. PGE customers on smaller schedules have greater potential for load shifting, to move their energy consumption to a different time interval while keeping their total electricity consumption constant. Schedule 90 customers typically operate around the clock and have less potential for load shifting.

Q. What was PGE's approach to price development for each peak window?

A. PGE constructed a cost-based approach that centers on the allocation of marginal energy costs to on-, mid-, and off-peak windows using forecasted Mid-C market prices and proportional consumption per period. Figure 2 provides an example of this methodology for Schedule 83.

Figure 2
Schedule 83 Example of Marginal Cost Allocations

Window	Average Hourly Forecasted Mid-C Price	Proportional kWh	Proportional Marginal Energy Costs
On-peak	98.14	19.1%	23.0%
Mid-peak	85.22	45.5%	47.5%
Off-peak	67.99	35.4%	29.5%

The calculated price differentials between on-/mid-peak and mid-/off-peak for each schedule informed a common set of differentials applied to Schedules 83, 85 and 89.

PGE applies a slightly broader spread between on-/mid-peak and mid-/off-peak prices for Schedule 38. Due to the absence of a demand charge, the use of a wider price spread gives customers on the optional Schedule 38 price signals that better align with PGE's cost to serve.

Q. Per the Fourth Partial Stipulation, did PGE perform an analysis showing the effect that eliminating the residential energy block rate would have on customer usage?

A. PGE does not have sufficient data to conduct this analysis at this time since the blocking only ceased on January 1, 2024. PGE can perform and provide an analysis once usage data for at least six months without blocking is available.

III. Rate spread

Q. What is the basis for the functional allocation of costs to the rate schedules?

A. We use the marginal cost of service study to inform the allocation of the generation, transmission, distribution, and customer service functional revenue requirements in the rate-spread process. The customer service component consists of Metering, Billing, and Other Consumer Services. The marginal cost of service study is presented in PGE Exhibit 801.

Q. How do you calculate and allocate the 2025 test-period marginal generation capacity costs to the individual rate schedules?

A. To obtain the marginal generation capacity costs, we multiply the real levelized annual capacity cost[2] by the projected 2025 cost of service (COS) peak-hour load, which is forecasted to occur in August. We then allocate the marginal generation capacity costs based on each rate schedule's relative contribution to the average monthly peak hour load across January, July, August, and December. This is called a 4-coincident peak (4 CP) allocation approach.

Q. Why do you choose these four months?

A. PGE chooses these four months because they have the highest monthly peaks consistent with the periods identified as capacity deficient in PGE's 2023 Integrated Resource Plan. Additionally, PGE's highest annual peak load hours generally occur during one of these four months.

Q. What are the respective capacity and energy percentages used in allocating the generation revenue requirements?

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[2] *See* PGE Exhibit 800.

A. Capacity comprises approximately 34% of the marginal cost of generation and energy approximately 66%. These figures reflect the inclusion of load following costs as a capacity cost. The corresponding figures from UE 416 were approximately 36.3% and 63.7%.

Q. How do you allocate the costs of the Seaside Battery project?

A. We allocate the costs of the Seaside Battery project to the COS rate schedules in the same manner as the generation revenue requirement discussed above. We provide impacts associated with the January 1 revenue requirement separately and then provide the combined impacts associated with the January 1 revenue requirement inclusive of the impacts of the Seaside Battery project. The difference between the two revenue requirements reflects the Seaside Battery project and the ITC benefits.

Q. How will the price changes for the Seaside Battery project be implemented?

A. PGE will implement the changes in the COS Energy Charges and the Schedules 128, 129, and 139 Transition Adjustments as appropriate through a compliance filing in this docket. Because changes in Schedules 129 and 139 revenues impact either Distribution Charges or System Usage Charges, PGE will include these changes in the filing. If the Commission approves PGE Advice No. 24-01,[3] then PGE will file for the appropriate changes in Schedule 123 Decoupling Adjustment to reflect the increases in fixed costs.

Q. Would the same be true for the Constable Battery project?

A. PGE is including the Constable Battery project in prices effective January 1, 2025 based on its anticipated in-service date of December 31, 2024. However, if the project online date was to shift, PGE would separate the impact of the Constable Battery project and use the same treatment as that described for the Seaside Battery project.

[3] Docketed as UE 432.

Q. How do you allocate the transmission revenue requirement?

A. We allocate the transmission revenue requirement based on each rate schedule's 12 monthly coincident peaks (12 CP) multiplied by the unit marginal transmission costs presented in PGE Exhibit 801. This methodology is consistent with PGE's last GRC, UE 416, and the approach used to allocate transmission costs to PGE wholesale customers in PGE's Open Access Transmission Tariff (OATT).

Q. Please describe how PGE functionalizes transmission lines that serve as generation leads.

A. PGE first functionalizes the generation lead transmission lines, such as the Colstrip transmission facilities and the Port Westward to Trojan lines, to generation. Then, through the revenue requirement allocation process, PGE ensures that generation lead transmission lines are allocated based on both capacity and energy. PGE's wheeling expense from purchasing Bonneville Power Administration (BPA) transmission is also functionalized to generation and allocated based on energy and capacity in proportion to the generation revenue requirement allocation.

Q. Why is it appropriate to allocate PGE transmission costs to capacity?

A. It is appropriate because the transmission investments included in the marginal cost study is determined as a function of peak loads. Furthermore, the transmission investments included in the transmission marginal cost study do not include generation lead transmission lines that are classified to generation and allocated on both an energy and capacity basis. PGE functionalizes to generation the generation lead high voltage transmission facilities that bring major production sources to PGE's service territory. Those transmission facilities are functionalized to energy and capacity, following the generation allocation. For example, PGE integrates the Carty natural gas plant with BPA transmission. The cost of this transmission is contained in net variable power costs and is therefore functionalized to generation. The Grassland switchyard, constructed to connect Carty to BPA's Slatt substation via the Boardman-Slatt generation lead, is also functionalized to the generation revenue requirement. As a result of this functionalization, most of the transmission used to bring Carty power to PGE's service territory is allocated on an energy basis. The same is true of other PGE generating resources that use BPA transmission.

Q. What other functional revenue requirement categories do you allocate besides those mentioned above?

A. Because the Ancillary Services revenue requirement is split out from generation, we allocate it in the same manner as generation. The Ancillary Services functional category combined with the six categories above (generation, distribution, transmission, billing, metering, and other consumer services) complete the seven functional categories specified in Oregon Revised Statute (ORS) 757.642 and discussed in Exhibit 200.

Q. Do you allocate other cost categories to individual rate schedules?

A. Yes. We allocate franchise fees to the rate schedules based on the test period revenue requirement allocations and allocate the Trojan decommissioning on a generation revenue basis. We allocate Schedule 129 and Schedule 139, Long-Term Transition Adjustments, on an energy basis to all schedules. This allocation is consistent with the allocation used in recent GRCs. Finally, we allocate uncollectible expense based on historical incidence for the period 2017 to 2019. PGE is using this period due to abnormalities in write-offs caused by the COVID-19 pandemic in the years 2020, 2021, and 2022. All allocations are presented in PGE Exhibit 904.

Q. Please describe how you allocate and price the recovery of franchise fees consistent with Commission Order No. 12-500.

A. We allocate franchise fees in the same manner as in UE 416, which does not attribute cost responsibility for the generation and transmission functional categories to direct access customers. More specifically, we allocate the franchise fee revenue requirements by segregating the generation and transmission revenue requirement test-period allocations from the other revenue requirement allocations across the schedules and separately calculate the prices for each category of allocations. Because direct access customers do not pay generation and retail transmission charges to PGE, we calculate a franchise fee price differential related to these charges and apply this differential to the direct access schedules. This differential is inclusive of Schedule 129 and Schedule 139 revenues and is captured in the system usage charges for each direct access schedule. For direct access schedules that do not have an explicit system usage charge, we establish a price differential within the volumetric distribution charges.

Q. Do you propose any form of rate mitigation or other deviation from using marginal cost to spread the revenue requirement?

A. Yes. We make several changes from the initial allocation of revenue requirement. The first change is that we reallocate between Schedules 89 and 90 the initial transmission, ancillary service, and distribution cost allocations that comprise the transmission and distribution demand charges for the two schedules. The second change is that after spreading the revenue requirement, we equalize the Distribution charges for Schedules 15, 91, and 95[4] through the

[4] Schedule 15-Outdoor Area Lighting, Schedule 91-Street and Highway Lighting Standard, Schedule 95- Street and Highway Lighting New Technology.

Customer Impact Offset (CIO). We do this for area and street lighting because the services provided are so similar in nature.

Q. Why do you reallocate some of the initial transmission, ancillary, and distribution cost allocations between Schedules 89 and 90?

A. We reallocate the transmission, ancillary services, sub-transmission, and substation costs between the two rate schedules because all the cost categories are facilities with the same unit marginal cost. However, because Schedule 90 has only two customers with seven accounts engaging in similar activity, there is less diversity of the demand billing determinants relative to Schedule 89, which has multiple customers engaged in different manufacturing activities.

The differences in diversity of demand billing determinants are important; Schedule 90 has a higher non-coincident peak load factor than Schedule 89 and has relatively lower unit feeder costs (per kW) than Schedule 89. Absent reallocating the cost categories above, Schedule 90 would have higher applicable distribution prices than Schedule 89 due to the relative lack of demand billing determinants over which to spread costs. Given that most of the cost categories above have the same unit costs, this result would not make intuitive sense. Therefore, we propose the reallocation of the above costs based on billing demand. We do not propose the reallocation of the other cost categories such as generation and customer service because these categories have unique cost attributions that yield reasonable prices.

IV. Rate Schedule Design

Q. Please provide a brief summary of the major COS rate schedules.

A. There are six major COS rate schedules:

Schedule 7, Residential Service, currently consists of a monthly Basic Charge, volumetric Transmission and Distribution Charges, and an Energy Charge.

Schedule 32, Small Non-residential Standard Service (30 kW or less), consists of a monthly Basic Charge, a volumetric Transmission Charge, and a two-block Distribution Charge. The Energy Charge is flat across all energy usage.

Schedule 83, Large Non-residential Standard Service (31 kW to 200 kW), applies to all secondary voltage Large Non-residential customers between 31 kW and 200 kW, except for certain specialty schedules. This schedule contains more complex charges than Schedules 7 and 32. In addition to the Basic Charge, there is a Transmission Demand Charge based on the highest metered kW reading for a 30-minute period during peak periods within the monthly billing cycle. There is also a Distribution Demand Charge and Generation Demand Charge based on the same criteria above, and a Distribution Facility Capacity Charge based on the average of the two greatest monthly Demands within a 12-month period (Facility Capacity). The Energy Charge is comprised of a mandatory TOU and includes the Generation Demand Charge.

Schedule 85, Large Non-residential Standard Service (201 kW to 4,000 kW), applies to secondary and primary voltage customers from 201 kW to 4,000 kW. The Schedule 85 Transmission and Distribution Demand Charges as well as the Facility Capacity Charges are based on the same criteria as they are for Schedule 83. The Energy Charge is comprised of a mandatory TOU and includes the Generation Demand Charge.

Schedule 89, Large Non-residential Standard Service (>4,000 kW), applies to customers whose Facility Capacity exceeds 4,000 kW. This schedule contains Transmission and Distribution Demand Charges that are based on the 30-minute periods that occur during peak intervals. These peak intervals are defined as between 6:00 a.m. and 10:00 p.m., Monday through Saturday. The Schedule 89 Distribution Facility Capacity Charge billing determinant is calculated in the same manner as for Schedules 83 and 85. The Energy Charge is comprised of a mandatory TOU.

Schedule 90, Large Non-residential (>4,000 kW, aggregating to exceed 30 MWa), applies to customers whose Facility Capacity exceeds 4,000 kW and whose aggregate energy consumption exceeds 30 MWa with a second set of energy prices for customers whose aggregate energy consumption exceeds 250 MWa. The rate design is similar to Schedule 89, but with higher customer charges.

Q. Do you continue the load following/integration credit for Schedule 90?

A. Yes. We continue this concept, applicable to 360 MWa based on expected average load, and to incorporate the credit amount of approximately $15 million into the base energy charges for Schedule 90 customers. In addition, it only applies to customers with aggregate load over 250 MWa. This $15 million is allocated to other COS customers except lighting customers and recovered through their respective energy charges.

Q. Did you update the load following/integration credit price that is used to calculate the load following/integration credit for Schedule 90?

A. Yes. The load following/integration credit price was last updated in PGE's 2018 GRC, in Docket UE 319. In this filing, we have updated the price to 4.89 mills/kWh based on the flexibility value of a four-hour battery in Docket LC 80, PGE's most recently acknowledged

2023 Integrated Resource Plan. We then apply a 63.6% ratio based on the total Allocated Capacity and Energy Costs to total Marginal Capacity and Energy Costs.

Q. What methodology do you use to allocate the credit to other COS customers?

A. We allocated the credit to other COS customers using marginal generation energy, this is the same method that was used in UE 416 and previous GRCs.

Q. Please provide additional context for the proposed changes to Schedule 90.

A. PGE began an evolution of its cost-of-service rate classes for nonresidential customers over 20 years ago to enable Senate Bill (SB) 1149 with recognition of only two nonresidential base rate schedules (Schedule 32 and Schedule 83). Over time, that evolution led to recognition that different demand thresholds should be used to better define the characteristics of these customers and their impacts on system costs. Subsequently, the Commission approved the establishment of Schedules 85 and 89. Further, we recognized that for the largest customers, demand thresholds should serve as the basis to refine customer class and that customer load factor should be considered as well. The load factor criteria factored into the development of Schedule 90.

Q. Did the characteristics of any of your large customers play a role in your thinking about this evolution?

A. Yes. PGE's largest customer is currently the only customer on the over 250 MWa portion of Schedule 90. That customer is many multiples in size larger than our next largest customer and has grown significantly in the past few years. The benefits of volume and load factor associated with this individual customer are significant for the remainder of PGE's customer base. As that customer has grown, and as new and prospective customers with large loads and high load factors enter our service territory, it is necessary to further recognize the beneficial characteristics of these customers through our proposed modification to Schedule 90.

Q. Is Schedule 90 an economic development rate?

A. No. Both our current formation of Schedule 90 and our proposed Schedule 90 construct is based on traditional principles of ratemaking and cost allocation.

Q. What principles do you consider in developing the proposed prices?

A. We consider the following Bonbright[5] principles in both the cost allocation and pricing processes. The proposed prices should accomplish the following:

- Recover the total revenue requirement.
- Provide price stability and predictability to customers.
- Provide revenue stability and predictability to the utility.
- Reflect the cost of providing service to the applicable customer classes.
- Be fair to the customer classes.
- Send appropriate price signals.
- Be simple and understandable.

Q. How do you develop the prices for each rate schedule?

A. We explain the development of prices for each of the major rate schedules below. PGE Exhibit 903, Rate Design, provides additional detail regarding how the individual prices for each schedule were designed.

Q. Please list the individual monthly prices for Schedule 7, Residential Service.

A. The prices are summarized below in Table 2:

[5] Principles of Public Utility Rates, by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, 2nd Edition, 1988.

Table 2
Schedule 7 - Residential Service Proposed Prices

Category	Prices
Basic Charge – Single Family	$15 per customer per month
Basic Charge – Multifamily	$12 per customer per month
Transmission & Related Service Charge	8.90 mills per kWh
Distribution Charge	71.99 mills per kWh
Energy Charge	92.79 mills per kWh

Q. Please explain how you develop these prices.

A. The Basic Charge has separate charges for customers in multi-family and single-family dwellings. Although the embedded customer costs suggest a Basic Charge of approximately $30, we are only proposing to increase the Basic Charge for single-family family and multi-family dwellings by $2 from $13 to $15 monthly for single-family and $10 to $12 monthly for multi-family.

When we proposed the current basic charges, in opening testimony in UE 416, it allowed PGE to continue to recover 9% of a customer's bill via the Basic Charge as had been the case in UE 394. However, with changes to the final net variable power costs and resulting Basic Charge in UE 416, PGE is currently only recovering 8.4% of a customer's bill via the Basic Charge. Without updating, PGE would recover only 7.7% of the bill via the Basic Charge. PGE's proposal to increase the Basic Charge by $2 for residential customers will allow to PGE to recover roughly 9% of a customer's bill via the Basic Charge, which brings the Basic Charge back in line with UE 394. These proposed prices get closer to embedded costs, consistent with the principles discussed above, while still recognizing the lower costs to serve and the differences in income and energy burden between customers in multi-family versus single-family dwellings. Furthermore, PGE's Income Qualified Bill Discount (IQBD) will temper a Basic Charge increase for low-income customers enrolled in the program, which is expected to reach 100,000 customers by the end of 2024.

We develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

We calculate the **Distribution Charge** of 71.99 mills per kWh from the allocated distribution costs and from the allocated costs not recovered by the other charges. The Distribution Charge also includes the allocation of franchise fees and Trojan Decommissioning costs.

Q. Why are revenue impacts of the Schedule 7 voluntary portfolio Time of Day (TOD) option not included in the calculation of Schedule 7 prices?

A. PGE's TOD option stems from the Company's Flex 1.0 pilot project and, along with Peak Time Rebate, comprises our Flex 2.0 program, encouraging residential customers to shift usage away from high demand periods. TOD is still a relatively new offering and customer enrollments continue to grow from month to month, making revenue impacts difficult to forecast over the multi-year window between GRCs. While TOD is still a growing offering, revenue impacts will be addressed via Schedule 105, per PGE's tariff. Once TOD enrollments have reached maturity and demonstrate relative consistency month over month, PGE expects to incorporate revenue impacts in a future GRC process.

Q. Please list the individual monthly prices for Schedule 32, Small Nonresidential Service.

A. The prices are summarized below in Table 3:

Table 3
Schedule 32 - Small Nonresidential Service

Category	Prices
Basic Charge Single Phase	$24.00 per customer per month
Basic Charge Three Phase	$33.00 per customer per month
Transmission & Related Services Charge	7.18 mills per kWh
Distribution Charge First 5,000 kWh	73.95 mills per kWh
Distribution Charge Over 5,000 kWh	34.74 mills per kWh
Energy Charge	82.56 mills per kWh

Q. Please describe how you develop the Schedule 32 prices.

A. Schedules 32 and 532 apply to Small Nonresidential customers, with Facility Capacity less than or equal to 30 kW. Schedule 532 (applicable to Direct Access Service) is a subset of Schedule 32 in that it contains some, but not all, of the cost components of Schedule 32. Small Nonresidential customers receive service at secondary voltage, and other than the Basic Charge, all charges are expressed as a volumetric kWh charge. As with Schedule 7, the applicable costs are allocated into the Basic, Transmission, Distribution and Energy Charge categories. As with Schedule 7, we capture the difference between the allocated costs and the various revenues within the Distribution Charge.

The embedded customer costs suggest a **Basic Charge** of approximately $45 for single phase and $56 for three-phase. We are proposing to increase the Basic Charge by $2.00 from the current $22 to $24 monthly amount for single-phase and from the current $31 to $33 monthly amount for three-phase. When we proposed the current basic charges, in opening testimony in UE 416, it would allow PGE to recover 12% of a customer's bill via the Basic Charge, down from the 14% that was recovered in PGE's 2019 test year GRC, Docket No. UE 335 (UE 335). However, with changes to the final NVPC's in UE 416, PGE is currently only recovering 11.7% of a customer's bill via the Basic Charge. PGE's proposal to increase the Basic Charge by $2 results in 11.5% of the customer's bill consisting of the Basic Charge. Without updating, PGE would recover only 10.7% of the bill via the Basic Charge. These proposed prices better match prices to embedded costs, consistent with Bonbright's principles.

We compute the **Transmission and Related Services Charge** directly from the allocated transmission and ancillary service costs.

We retain the current Schedule 32, **Distribution Charge** blocking, with the initial block including usage up to 5,000 kWh. We set the second block for usage greater than 5,000 kWh on a declining basis to 30 mills per kWh (prior to adding the System Usage Charge) to provide a transition to Schedule 83 for customers whose loads have exceeded 30 kW at least twice during the preceding 13 months. The design provides effective rate migration for customers who migrate from volumetric-based distribution pricing to demand-based distribution pricing (Schedule 32 to 83). Similar to Schedule 7, we include within the Distribution Charge the costs associated with franchise fees and Trojan Decommissioning.

We set the **Energy Charge** on a flat year-round basis that is based on the allocation of generation costs.

Q. Do you incorporate a projection of the revenue impacts of the voluntary portfolio TOU option in the calculation of the energy price?

A. Yes. We estimate that by continuing to price the voluntary TOU in a manner that presumes customers' load shape is the same as the overall rate schedule, PGE will incur a revenue shortfall of approximately $36,000. We incorporate this impact in the standard Schedule 32 energy charge.

Q. Briefly describe Schedule 532.

A. Schedule 532 sets out the charges associated with PGE's distribution services. Energy supply and transmission costs are excluded because the customer's ESS provides these services.

Schedule 532 includes the same Basic and Distribution Charges as Schedule 32, with the exception of the distribution price reduction associated with franchise fees discussed earlier in this testimony. This distribution price reduction is also applicable to Schedules 538, 549, 491/591, 492/592, and 495/595. We incorporate a Daily Price Energy Charge into Schedule 32 to address the potential cost impact of customers switching from Schedule 532 to Schedule 32 prior to completing at least one year of service on Schedule 532. The daily price tracks the daily market price for power and is based on the secondary voltage Daily Price option in Schedule 83.

Q. Please provide the proposed prices for Schedule 83 and describe the customers to whom these prices apply.

A. Schedule 83 applies to all non-residential customers with Facility Capacity loads greater than 30 kW and less than or equal to 200 kW. We use the same approach and cost causation principles as described for Residential and Small Nonresidential service in designing these prices. The Schedule 83 charges include more detail because Large Nonresidential customers are generally more sophisticated energy users and are more able to react to pricing signals triggered by their peak consumption. Schedule 83 is for secondary delivery voltage only. The proposed prices are listed below in Table 4:

Table 4
Schedule 83 - General Service 31-200 kW

Category	Monthly Price
Basic Charge Single Phase	$50.00 per customer per month
Basic charge Three Phase	$60.00 per customer per month
Trans & Related Services	$2.78 per on-peak kW
Facility Capacity Charge (First 30 kW)	$6.31 per kW Facility capacity
Facility Capacity Charge (Over 30kW)	$6.21 per kW Facility Capacity
Distribution Demand Charge	$1.73 per on-peak kW
Generation Demand Charge	$9.34 per on-peak kW
COS Energy Charge On-peak	63.44 mills per kWh
COS Energy Charge Mid-peak	55.44 mills per kWh
COS Energy Charge Off-peak	43.44 mills per kWh
System Usage Charge	13.44 mills per kWh

Q. Please describe how you develop the Schedule 83 prices.

A. We propose to increase the current Schedule 83 single-phase **Basic Charge** of $40 to $50 and the three-phase charge of $50 to $60. The Basic Charge was last increased in UE 416. Increasing the Basic Charge allows PGE to recover our embedded customer costs at the same percentage of the bill as in 2024. This pricing level helps enable a smooth transition for Schedule 32 customers whose demand exceeds 30 kW and move to Schedule 83. Similar to Schedule 32, these basic charges are set considerably below the embedded customer-related costs. The System Usage Charge recovers the remaining customer-related costs as well as any other costs either not fully recovered or more than fully recovered through the appropriate charge.

For Schedules 83, we set the **Transmission & Related Service Charge** to $2.78 per kW of peak demand consistent with the other secondary voltage customers served on Schedules 85 or 89. We do this to make the pricing more consistent for customers who choose Direct

Access Service under Schedules 583, 485/585, 489/589, or 490/590. This charge results in more than full recovery of Schedule 83 allocated costs; consequently, we flow the over-recovery through to the System Usage Charge.

The **Distribution Charges** for Schedule 83 consist of a **Demand Charge** and a **Facility Capacity Charge**. We recover the costs associated with 13 kV facilities through the Facility Capacity Charge. We set the Facility Capacity Charge for the first 30 kW minimally higher than the Facility Capacity Charge for over 30 kW to provide a smooth transition for Schedule 32 customers who migrate to Schedule 83 because their demand exceeds 30 kW. This declining block structure also reflects the declining unit cost nature of the distribution system.

We set the **Distribution Demand Charge,** which recovers distribution substations and radial 115 kV costs where applicable, at $1.73 per kW of on-peak demand by combining the demand-related costs and billing determinants for Schedules 83, 85, 89, and 90 such that these schedules will have the same secondary voltage and primary voltage demand charges. Any over- or under-collections of these demand-related costs are captured through other charges applicable to the specific schedules.

Because several energy options are available to Schedules 83 and 583, we separately state the **System Usage Charge.** This charge recovers franchise fees and Trojan Decommissioning costs, as well as any other costs not fully recovered by the other charges. Again, the System Usage Charge is lower for Schedule 583 than for Schedule 83 because Schedule 583 customers are not charged for generation and transmission by PGE.

We calculate the **COS Energy Charges** based on the results of the generation allocations The Energy Charge is comprised of a mandatory TOU that has an on-/ mid-peak price differential at 8 mills per kWh and has a mid-/off- peak price differential at 12 mills per kWh and includes the Generation Demand Charge.

Q. Please describe the Schedule 83 Energy Charge options.

A. Schedule 83 customers may choose to receive energy either from PGE based on PGE's COS energy option or from PGE's market-based energy option. The market-based option available to Schedule 83 is daily pricing based on the prices for the Mid-Columbia (Mid-C) hub as reported by the Intercontinental Exchange Daily On- and Off-Peak Firm Pricing Index (ICE Mid-C Firm Index). Customers may also choose to receive service from an ESS, the details of which are discussed below.

Customers receiving service from an ESS or a PGE market option receive the Schedule 128, Short-Term Transition Adjustment.

Q. What schedule applies to Schedule 83 customers who wish to elect the Direct Access energy option?

A. Customers choosing the Direct Access energy option will take service under the provisions of Schedule 583. Schedule 583 pricing mirrors Schedule 83 except that it contains neither a PGE-supplied energy price nor a Transmission & Related Services Charge. In addition, consistent with the franchise fee discussion above, the System Usage prices for Schedule 583 are lower than those for Schedule 83. This is also true for Schedules 485/585, 489/589, and 490/590 relative to their COS equivalent schedules.

Q. Please provide the proposed monthly prices for Schedule 85 and describe the customers to whom these prices apply.

A. Schedule 85 applies to all Large Nonresidential customers whose Facility Capacity demands are between 201 kW and 4,000 kW. Those customers whose facility capacity exceeds 4,000 kW take service under Schedule 89, which we discuss below. We base the individual charges on the results of the marginal cost study and subsequent rate spread, paying particular attention to appropriately pricing the cost differentials between secondary and primary delivery voltages. The prices differentiated by delivery voltage are in Table 5 below:

Table 5
Schedule 85 General Service 201-4,000 kW

Category	Secondary Prices	Primary Prices
Basic Charge	$800.00 per customer per month	$750.00 per customer per month
Trans & Related Services	$2.78 per on-peak kW	$2.75 per on-peak kW
Facility Capacity Charge (First 200 kW)	$3.47 per kW Facility Capacity	$3.43 per kW Facility Capacity
Facility Capacity Charge (Over 200 kW)	$3.37 per kW Facility Capacity	$3.33 per kW Facility Capacity
Distribution Demand Charge	$1.73 per on-peak kW	$1.71 per on-peak kW
Generation Demand Charge	$10.62 per on-peak kW	$10.50 per on-peak kW
COS Energy Charge On-peak	61.55 mills per kWh	61.00 mills per kWh
COS Energy Charge Mid-peak	53.55 mills per kWh	53.00 mills per kWh
COS Energy Charge Off-peak	41.55 mills per kWh	41.00 mills per kWh
System Usage Charge	2.88 mills per kWh	2.85 mills per kWh

Q. Please describe how you develop the Schedule 85 prices.

A. The Schedule 85 **Basic Charges** differ by delivery voltage. For secondary service and primary voltage, we set the monthly Basic Charges at $800 and $750, respectively. These Basic Charges, subject to rounding, recover the full amount of the allocated customer-related costs except for the marginal costs of transformer and service drops for secondary voltage customers, which are recovered through the facility capacity charges. Recovery of these costs through the facility capacity charges provides a differential between primary and secondary facility capacity charges similar to that stipulated to in UE 319. These customer charges combined with the declining block facilities charges also help transition those Schedule 83 customers whose demand grows to exceed 200 kW.

For Schedules 83, 85, 89 and 90, we set the **Transmission & Related Service Charge** to $2.78 per kW of peak demand for secondary service and $2.75 per kW for primary service, prices that are similar to the Schedule 85 allocated revenue requirements.

The **Distribution Charges** for Schedule 85 consist of a **Demand Charge** and a **Facility Capacity Charge**. For both secondary and primary voltage customers, we recover the costs associated with 13 kV facilities through the Facility Capacity Charge. The difference between secondary and primary voltage Facility Capacity Charges reflects the difference in estimated peak demand losses for the respective delivery voltages. The Facility Capacity Charge also recovers any over- or under-recovery of the other charges.

The **Distribution Demand Charges** of $1.73 and $1.71 for secondary and primary voltage customers, respectively, are set in conjunction with the demand charges for Schedules 83, 89, and 90 as discussed earlier. We calculate the demand charge difference based on the difference in peak demand losses of the respective delivery voltages.

Because several energy options are available to Schedules 85 and 585, we separately state the **System Usage Charge** which recovers franchise fees, Trojan Decommissioning costs, and the CIO. We also use this charge for Schedules 83, 85, 89, and 90 to capture the Schedule 129 and Schedule 139 transition adjustment revenues and the generation fixed cost contribution true-ups of either returning or departing long-term direct access customers. The System Usage Charge is lower for both Schedules 485 and 585 for the reasons stated earlier in this testimony.

We calculate the COS energy charges based on the results of the generation allocations. The **Energy Charge** is comprised of a mandatory TOU that has an on-/mid-peak price differential at 8 mills per kWh and has a mid-/off peak price differential at 12 mills per kWh and includes the Generation Demand Charge.

We calculate the energy price difference between the secondary and primary voltage customers based on the difference in embedded line losses.

Q. Please describe the Schedule 85 Energy Charge options.

A. The Schedule 85 energy price options are the same as those for Schedule 83 described above with the exception that qualifying customers may choose long-term direct access through Schedule 485. Schedule 85 customers may also choose the annual direct access option through Schedule 585.

Q. Please provide the proposed monthly prices for Schedule 89 and describe the customers to whom these prices are applicable.

A. Schedule 89 applies to all Large Nonresidential customers whose Facility Capacity exceeds 4,000 kW. The Schedule 89 prices, differentiated by delivery voltage, are in Table 6 below:

Table 6
Schedule 89 General Service Greater than 4,000 kW

Category	Secondary Prices	Primary Prices	Subtransmission Prices
Basic charge	$4,190.00 per month	$4,140.00 per month	$5,860.00 per month
Transmission & Related Charge	$ 2.78 per on peak kW	$2.75 per on peak kW	$2.70 per on peak kW
Facility Capacity Charge First 4,000 kW	$2.04 per kW Facility Capacity	$2.02 per kW Facility Capacity	$2.00 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.73 per kW Facility Capacity	$1.71 per kW Facility Capacity	$1.69 per kW Facility Capacity
Distribution Demand Charges	$1.73 per on-peak kW	$1.71per on-peak kW	$0.13 per on-peak kW
COS Energy Charge On-peak	85.53 mills per kWh	84.73 mills per kWh	83.91 mills per kWh
COS Energy Charge Mid-Peak	77.53 mills per kWh	76.73 mills per kWh	75.91 mills per kWh
COS Energy Charge Off-Peak	65.53 mills per kWh	64.73 mills per kWh	63.91 mills per kWh
System Usage Charge	2.44 mills per kWh	2.41 mills per kWh	2.38 mills per kWh

Q. Please describe how you develop the Schedule 89 Charges.

A. We set the **Basic Charges** for secondary, primary and subtransmission voltage customers at 100% of the customer-related costs for each delivery voltage.

The **Transmission and Related Service Charge** is calculated in conjunction with Schedules 83, 85, and 90 for the reasons previously discussed. Because this charge is less than the allocated costs, the Facility Capacity Charge recovers the remainder.

As specified above, we calculate the **Distribution Demand Charge** in conjunction with Schedules 83, 85, and 90. Any under-collection of costs is recovered through the Facility Capacity Charge. For both secondary and primary voltage customers, the Distribution Demand Charge reflects the marginal cost of providing substations and shared subtransmission facilities, subject to the conjunctive pricing with other schedules referenced above. For customers served at subtransmission voltage who supply their own substation, the Distribution Demand Charge reflects the costs of the shared subtransmission system, again subject to the conjunctive pricing with other rate schedules. It also reflects the cost per kW differential between connecting a customer of equal size with a 13 kV feeder or a feeder at 115 kV. This differential of $1.58 per kW is subtracted from the Distribution Demand Charge to equalize the Facility Capacity Charge for primary voltage and subtransmission voltage delivery. As with Schedule 85, we set the delivery voltage price differentials based on the peak demand loss differences of the respective delivery voltages.

The **Facility Capacity Charge** for Schedule 89 customers has two blocks: one for the first 4,000 kW, and the second for billing kW greater than 4,000 kW. We set the first block charge 31 cents per kW higher than the second block to reflect the estimated applicable difference in unit costs between different feeder wire gauges and their load carrying capabilities. The Facility Capacity Charges reflect the peak demand loss difference between providing service at secondary or primary voltage service. As mentioned above, we set the Facility Capacity Charge for subtransmission voltage customers equal to that of primary voltage customers and flow any cost difference to the subtransmission voltage Demand Charge.

The **COS Energy Charge** option for Schedule 89 is differentiated by delivery voltage and is comprised of a mandatory TOU that has an on-/mid-peak price differential at 8 mills per kWh and has a mid-/off -peak price differential at 12 mills per kWh. A Daily Price option is also available similar to what is described for Schedule 83. Customers who opt for the Direct Access Energy Option and take service under Schedule 589. As with Schedules 83/583 and 85/485/585, Schedules 89 and 489/589 we separately identify the System Usage Charge, which is lower for direct access customers.

Q. Please provide the proposed monthly prices for Schedule 90 and describe the customers to whom these prices are applicable.

A. Schedule 90 applies to Large Nonresidential customers whose Facility Capacity exceeds 4,000 kW and whose aggregated load exceeds 30 MWa. All six of the accounts on Schedule 90 are served at primary delivery voltage; the prices are listed in Table 7 below:

Table 7
Schedule 90 General Service Greater than 4,000 kW aggregating to 30 MWa

Category	Primary Voltage Prices	Subtransmission Voltage Prices
Basic Charge	$18,500.00 per month	$18,500.00 per month
Transmission & Related Charge	$2.75 per on-peak kW	$2.70 per on-peak kW
Facility Capacity Charge First 4,000 kW	$2.05 per kW Facility Cap.	$2.05 per kW Facility Cap.
Facility Capacity Charge Over 4,000 kW	$1.74 per kW Facility Cap.	$1.74 per kW Facility Cap.
Distribution Demand Charge	$1.71 per on-peak kW	$0.13 per on-peak kW
COS Energy Charge On-peak (30-250MWa)	78.00 mills per kWh	76.73 mills per kWh
COS Energy Charge Off-peak (30-250 MWa)	63.00 mills per kWh	60.81 mills per kWh
COS Energy Charge On-peak (>250 MWa)	73.09 mills per kWh	72.27 mills per kWh
COS Energy Charge Off-peak (>250 MWa)	58.09 mills per kWh	57.27 mills per kWh
System Usage Charge (30-250 MWa)	2.42 mills per kWh	2.42 mills per kWh
System Usage Charge (>250 MWa)	2.42 mills per kWh	2.42 mills per kWh

Q. Please describe how you develop the Schedule 90 Charges.

A. We set the **Basic Charge** at 100% of customer-related costs consistent with how we price Schedules 85 and 89. In prior dockets, we set the Basic Charge at a level exceeding cost, but, because of the redistribution of certain allocated costs between Schedules 89 and 90, we set the Schedule 90 Basic Charge at cost.

Similar to Schedule 89, we calculate the **Transmission and Related Service Charge** in conjunction with Schedules 83, 85, and 89. Also, similar to Schedule 89, because this charge is less than the allocated costs, we use the Facility Capacity Charge to recover the remainder.

The **Distribution Demand Charge** is calculated in the same manner as we calculate the distribution demand charges for Schedule 89. It reflects the cost per kW differential between connecting a customer of equal size with a 13 kV feeder or a feeder at 115 kV. This differential of 1.58/kW is subtracted from the Distribution Demand Charge to equalize the Facility Capacity Charge for primary voltage and subtransmission voltage delivery.

We block the **Facility Capacity Charge** with the same price differential as Schedule 89 and flow through any over- or under-recovery of costs through this charge.

The **COS Energy Charge** is differentiated by on- and off-peak differentiated by delivery voltage. We maintain the current differential of 15 mills per kWh for Primary and Subtransmission >250 MWa. Primary and Subtransmission 30-250 MWa has a 15.93 mills per kWh differential for on- and -off-peak hours. There is also a Daily Price Option and Direct Access options similar to those for Schedules 85 and 89.

Q. Please discuss how you priced Schedules 38, 47 and 49.

A. **Schedule 38, Large Nonresidential Optional Time-of-Use Standard Service** is, as its name implies, an optional schedule that applies to customers whose facility capacity is between 31 and 200 kW for Standard Service and standalone EV Charging up to 4000 kW. The embedded customer costs suggest a **Basic Charge** of approximately $104 for single phase and $165 for three-phase. We propose to increase the monthly Basic Charge by $15 from $35 to $50 for single-phase service customers and by $25 from $35 to $60 for three-phase service customers. The proposed Basic Charges match Schedule 83 since Schedule 38 is an optional schedule for Customers on Schedule 83. We maintain the volumetric recovery of transmission and distribution costs and propose to differentiate the energy charges based on the on-, mid- and off-peak periods defined in Schedule 38. We increase the overall differential between on- and off-peak hours from 15 to 30 mills per kWh, with an on-/mid-peak differential of 10 mills and a mid-/off-peak differential of 20 mills. Schedule 38 customers may take Direct Access Service under Schedule 538.

Schedule 47, Irrigation and Drainage Pumping Small Nonresidential Standard Service, applies to Small Nonresidential customers whose demand does not exceed 30 kW. We are not proposing to increase the Basic Charge from current $39 per month, applicable during the months of May through October. We maintain the blocked volumetric distribution charges for these schedules as well as the volumetric recovery of transmission and generation costs. The direct access equivalent schedule for Schedule 47 is Schedule 532.

Schedule 49, Irrigation and Drainage Pumping Large Nonresidential Standard Service, is similar to Schedule 47 but applies to customers larger than 30 kW. We propose to increase the Basic Charge by $10 from $50 to $60. The Basic Charge was increased in UE 416; PGE's proposal to increase the Basic Charge by $10 results in 4% of the customer bill consisting of the Basic Charge which is still below what was previously recovered in 2019. Schedule 49 customers may take Direct Access Service under Schedule 549.

Q. Please describe the development of charges for the remaining rate schedules.

A. The remaining proposed rate schedules provide service to lighting and traffic signal customers and are discussed below:

We structure **Schedule 15, Outdoor Area Lighting Standard Service** charges in the same manner as the current rate schedule. The Monthly Charge contains all of the allocated costs based on the specific kWh usage by luminaire. Schedule 515 provides this customer class with Direct Access Service charges.

Schedules 91/491/591 and 95/495/595, Street and Highway Lighting Standard Service, provide municipalities with outdoor lighting service. These schedules are similar in structure to Schedule 15. Each service option monthly rate includes the applicable unbundled costs, based on the monthly kWh usage of the particular type of light. A summary of the proposed pole and luminaire prices for the lighting schedules is provided in PGE Exhibit 905.

Schedule 92, Traffic Signals Standard Service, is an energy-only rate for unmetered traffic control devices in systems with at least 50 intersections. We retain the energy-only nature of the rate.

Schedule 592, Traffic Signals Direct Access Service, provides the Direct Access related energy-only based charge for this specialty service. Schedules 92/592 remain closed to additional governmental agencies.

Q. Why and how do you limit the amount of increase to some rate schedules?

A. We limit the increases to Schedules 38, 47 and 49 customers to 1.5 times the proposed overall all-in average price increase (excluding LIA and PPC) by allocating the increases to the lowest impacted schedule, in this case Schedule 90. After the CIO allocations, Schedule 90 receives neither an increase or decrease on an all-in price change basis (excluding LIA and PPC) and remains unchanged. This method is the same as the method described and employed in the Fourth Stipulation adopted through Commission Order No. 23-386 in UE 416. As specified earlier, we use the CIO to equalize the distribution prices for the outdoor lighting schedules because of the similar nature of the services provided.

Q. How do you implement the CIO?

A. For Schedules 38, 47 and 49 we decrease the distribution charges while increasing the system usage charges for Schedule 90. For Schedule 15, we increase the distribution charge while reducing the distribution charges for Schedules 91 and 95.

V. Other Rate Schedule Changes

A. Schedule 50- Retail Electric Vehicle Charging

Q. What changes do you propose for Schedule 50 in 2025?

A. PGE proposes to modify Schedule 50, Exhibit 906, to achieve three goals: first, to move to a per kWh rate for all Electric Vehicles (EVs), second, to add idle fees to encourage customers to move their vehicles once their charge is complete so that more customers can utilize the chargers, and third, to introduce an income-qualified rate to support equitable access to charging. In addition to these changes, Schedule 50 is being integrated into base rates and we are adjusting the rates for both Level 2 (L2) charging and Direct Current Fast Charging (DCFC). The on-peak period for Schedule 50 is being revised to match the Schedule 7 Time of Day hours as Schedule 50's on-peak period currently matches the on-peak period for Time of Use and that program will no longer be available starting January 1, 2025.

Q. Why is PGE proposing these changes?

A. These changes are being proposed because the costs associated with the infrastructure for Schedule 50 will be recovered through base rates, rather than through a deferral, as they are currently recovered. The changes to Schedule 50 also serve to align Level 2 charging rates with Schedule 7 rates to ensure equity between the rates that those charging their vehicles at home pay and those utilizing public chargers within our service area. We are also updating DCFC rates to be in line with the Portland metro area DCFC charging market. Based on lessons learned from the current offering, evolving technology options, and the local charging market, we are moving away from a subscription rate and instead replacing these with simple on- and off-peak volumetric rates with an income qualified rate option. By being responsive to user feedback and aligning with the market, PGE is also introducing an idle fee for both L2 and DCFC chargers.

Q. Please discuss the income qualified rate that is being introduced.

A. As our subscription rate is being eliminated, we are introducing an income-qualified rate to further the accessibility and equity of Electric Vehicle (EV) charging in communities that we serve. The introduction of this rate is consistent with our policies to support income-qualified customers. The income qualified rate will be available to those customers who qualified for IQBD. The discount will be available to customers through the charging station app and will automatically be applied when they enter their phone number tied to their PGE account. These customers will have access to a 20% reduction over the retail rates for Schedule 50.

Q. Please discuss how the L2 Schedule 50 rates were designed.

A. PGE conducted a survey of area EV charging rates for both L2 and DCFC chargers, as well as idle fees, where applicable. When considering the L2 rate, we wanted the price of $0.12/kWh to be comparable the weighted average of mid- and off-peak schedule 7 TOD rates plus a small adder to avoid the rate rapidly becoming out of line with residential rates. Our new L2 rate falls in the middle of the market that ranges from $0.07/kWh to $0.49/kwh. The on-peak adder of $0.28/kWh was set as to provide for an on-peak rate that is comparable to the TOD on-peak rate, which results in a price of charging during on-peak hours of $0.40/kWh. These changes encourage continuity across residential and utility-offered public charging rates and help align PGE's L2 charging rate with the L2 public charging market, ensuring equitable access to public charging, while also managing the load by encouraging customers to charge during off-peak hours through pricing signals.

Q. Please discuss how the L2 Schedule 50 idle fee was designed.

A. When considering the idle fee, we again looked to the market and sought to set an idle fee that was in line with the market, but while charging enough to encourage customers to move their vehicles so that others can utilize the charging stations. There will be a 10-minute grace period, after which a fee of $0.10 per minute will be assessed. Customers will be alerted via the charging app that their vehicle is finished charging and that the grace period is beginning. The idle fee will be part of the total EV charging charge, but a detailed breakdown is available to customers.

Q. Please discuss how the DCFC Schedule 50 rates were designed.

A. Similar to the L2 rates, PGE conducted market research and targeted the middle of the market with a $0.30/kWh off-peak charge with the same on-peak adder of $0.28/kWh (a total of $0.58/kWh on-peak) carried over from L2 charging. This is in alignment with the local market, which ranges from $0.17/kWh to $0.48/kWh. We acknowledge that our on-peak fee is greater than the market, but this serves to encourage customers to charge their vehicles during the off-peak window. Due to faster charging times and greater demand for public DCFC charging relative to L2 charging, we set the idle fee to $0.40 per minute after a 10-minute grace period to allow for higher utilization of DCFC chargers, which have a more rapid charging time. The $0.40 per minute is in line with a market comparison of DCFC idle fees ranging from $0.10/minutes to $1.00/minute.

B. Schedule 150- Transportation Electrification Cost Recovery Mechanism

Q. What Changes do you propose for Schedule 150 in 2025?

A. Effective January 1, 2025, we propose that all deferred costs associated with Transportation Electrification (TE) programs, specifically those costs associated with UM 1938, will move from recovery through Schedule 150 to recovery through base rates. Schedule 150 will remain in effect to recover the "monthly meter charge" revenues that utilities were directed to recover by House Bill (HB) 2165 and any trailing costs for UM 2003 will be covered by the monthly meter charge that will continue to be collected through Schedule 150.

C. Schedule 56

Q. Please describe the changes to Schedule 56.

A. A Transportation Line Extension Allowance (TLEA) is being added to Schedule 56 (Exhibit 907) to replace the currently active Fleet Commercial Make Ready Pilot upon full reservation of the funds available. Adding this TLEA to Schedule 56, rather than creating a new tariff allows PGE to streamline this tariff and provide a natural transition from the currently existing pilot program into the TLEA when all funds in the fleet pilot are reserved.

Q. Please describe the TLEA that PGE is proposing.

A. The TLEA being proposed in this general rate case will provide a long-term solution to enable customers to install charging infrastructure to electrify their fleets, while helping customers overcome the high initial cost and complexity of installing make-ready infrastructure. As stated in the TE plan, PGE is transitioning from pilots and programs and seeking to establish a rates and tariff structure that will result in a long-term solution to support the integration of electric vehicles and their load into PGE base business. This TLEA is the first iteration of a line extension agreement created to support planning and serving TE fleet load on all commercial schedules while giving a pathway to include additional use cases beyond fleet including managed charging.

Q. Has PGE proposed a TLEA before?

A. Yes, PGE proposed a TLEA in 2020 via Advice filing No. 20-17. Based on feedback from Staff and other intervening parties, PGE withdrew the TLEA proposal and proposed a fleet make-ready pilot, which is currently in operation as PGE Schedule 56: Commercial Electric Vehicle Make Ready Pilot.

Q. Why is PGE proposing a TLEA at this time?

A. PGE sees a growing need for more make-ready infrastructure and a long-term solution to providing support to customers, beyond what the Commercial Electric Vehicle Make Ready Pilot can offer. Customers are increasingly electrifying their fleets and the available funds for the Commercial Electric Vehicle Make Ready Pilot are rapidly dwindling. Consistent with the TE plan, PGE is working to transition TE programs from pilots to programs that are recovered through base rates, DEQ Clean Fuels program funding, or through HB 2165 funds. A TLEA will allow us to form partnerships with customers electrifying their fleets to ensure that this high-demand, high-powered infrastructure meets operational, safety, and interconnection requirements. Further, PGE needs to set operational and service expectations for electrified fleets as demand grows, partnering with these customers on load flexibility through demand response and rate design, but also through future collaboration on placement and utilization of local generation and storage. These partnerships will allow PGE to support future active management of load and provide the opportunity to utilize flex load from these sites during times of grid stress or emergency by requiring installation of utility qualified chargers which can support future load management programs.

Q. Will this TLEA minimize risk to other ratepayers?

A. Yes, the TLEA will minimize risk to ratepayers. Included in this proposal is a payback mechanism for customers who do not meet their committed load obligation by the end of the tenth year. This mechanism serves to help the customer seriously consider their vehicle electrification goals and commit to what they can support longer term, while helping them to right-size the installation so that major work is not required down the road should their fleet program expand past their near-term goals.

Q. How were the caps on the TLEA and the multiplier established?

A. Currently, when a Fleet Partner Pilot participant works with PGE to install EV charging, they are granted a line extension allowance (LEA) and a make ready incentive based on the year 5 annual energy use. This TLEA will be based on the committed 10-year total energy consumption and will combine the LEA with the make-ready incentive. The 1.4 multiplier times the applicable rate schedule LEA results in a similar total value to what is currently being offered to customers through the LEA and Fleet Partner Pilot make-ready incentive. The cap of $450,000 is based on the current cap of $400,000 in Fleet Partner plus an additional $50,000 to account for the average line extension allowance that customers would receive with the traditional LEA. We are switching from a year 5 annual energy use to a 10-year total energy consumption to better align the allowance calculation with the energy consumption commitment from the customer.

D. Schedule 105

Q. What is PGE planning to change in Schedule 105?

A. Concurrently with the beginning of the collection for the Seaside battery projects, we will seek to refund the value of the ITCs associated with both the Constable and Seaside projects to customers through Schedule 105 to offset the impact of the Seaside price increase. PGE Exhibit 500 testimony provides further details on this project, the ITCs associated with it, and our reasoning behind this timing.

E. Schedule 300 Updates

Q. Please describe PGE's Schedule 300.

A. Schedule 300, Charges as Defined by the Rules and Regulations and Miscellaneous Charges, is a schedule designed to directly assign and charge costs to customers who request services that are not generally within the normal operations of PGE's business or specifically benefit the requesting customer. Some examples may include reconnection or disconnection (for a reason other than safety), temporary electrical service, or the rental of equipment such as transformers. When these services are requested, the costs are assigned directly to the requesting customer. This direct application of cost-causation is consistent with Bonbright's principles of rate design, previously discussed in this testimony.

Q. Please describe the changes to Schedule 300 that PGE is requesting.

A. PGE is requesting Schedule 300 price changes as follows:

- Line extension allowances (Rule I) – PGE's Commercial Line Extension Allowances (LEA) were last updated in 2022 in UE 394. PGE proposes to update the commercial rate schedules using the proposed Basic and Distribution Charges for each Schedule contained in Exhibit 902.

The current and proposed Line Extension Allowances updates are shown in Table 8 below:

Table 8
Current and Proposed Commercial Line Extension Allowances

Schedule	Current	Proposed	Units
Sch 32	$0.2564	$0.3403	estimated annual kWh
Sch 38, 83	$0.1050	$0.1424	estimated annual kWh
Sch 85 & 89 Secondary	$0.0778	$0.0908	estimated annual kWh
Sch 85 & 89 Primary	$0.0429	$0.0412	estimated annual kWh
Sch 15, 91 & 95	$0.1529	$0.1881	estimated annual kWh
Sch 92	$0.0424	$0.541	estimated annual kWh
Sch 47 & 49	$0.0980	$0.1423	estimated annual kWh

Consistent with past practice that calculates the Line Extension Allowance using the Company's proposed Basic and Distribution Charge revenues and applying a Revenue multiplier, PGE employed the same methodology to update its proposed Line Extension Allowances. PGE is applying the previous Commercial Line Extension Allowance Revenue Multipliers that were used in 2022 to the proposed Basic and Distribution Charge revenues to calculate the proposed Line Extension Allowance amounts for 2025.

Q. Please describe any other changes to Schedule 300 that PGE is requesting.

A. PGE is requesting Schedule 300 price changes as follows:

- Service of Limited Duration (Rule L) rates for Standard Temporary Service have been updated to reflect current costs. The increase in PGE's Standard Temporary Service rates is reflective of its 2024 forecasted labor costs and Estimated Energy Cost. PGE's proposed Standard Temporary Service proposed prices are shown in Table 9 below:

Table 9
Current and Proposed Temporary Service Prices

Rate Type	Current Price	Proposed Price
Metered Temp - No Perm Service	$1,146	$1,225
Metered Temp - Existing Service	$870	$930
Metered Temp OH - Perm Service	$670	$725
Metered Temp UG - Perm Service	$672	$733
Enhanced Temporary Service (Gold-Temp) Unmetered Fixed Feed	$963	$1,069
Fixed Fee per 6-Month Renewal	$415	$479

- PGE's Wasted Trip Charge (Rule I Section 3) has been updated to reflect current costs. PGE is proposing a Wasted Trip Charge of $203. The current price is $180. This increase reflects PGE's 2025 forecasted labor costs. PGE last updated the Wasted Trip Charge in January 2024.
- Non-Network Residential Meter Rates (Rule M) rates have been updated to reflect current costs. PGE is proposing an installation of a non-network meter charge of $158. The current price is $140. PGE is proposing a non-network meter read charge of $30. The current price is $25 per month. These rates were last updated in January 2024. The increase in these charges is reflective of PGE's 2025 forecasted labor costs.
- Billing Rates (Rules C, E, F, H, J and M) have been updated to reflect current costs. PGE's proposed Billing Rates are shown in Table 10 below:

Table 10

Rate Type	Current Price	Proposed Price
Special Meter Reading Charge (non-network)	$25	$30
Meter Test Charge	$140	$158
Field Visit Charge	$50	$54

PGE's Pulse Output Metering (Rule M) has been updated to reflect current costs. PGE is proposing an Installation of Standard Meter Option (1 or 2 outputs) Charge of $575 and

Installation of Complex Meter Option (1 to 4 outputs) Charge of $1,525. The current prices are $350 and $1,300 respectively. This increase reflects PGE's 2025 forecasted labor costs. PGE last updated the Pulse Output Metering Charges in January 2022.

F. Rules and Regulations

Q. What change is PGE proposing to Rules and Regulations?

A. PGE is proposing to allow the inclusion of contractors employed by PGE within the Limitations of Liability in Rule C, Section C (PGE Exhibit 908).

VI. Qualifications

Q. Mr. Pleasant, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree in Art History from University of Oregon. I have been employed at PGE since 2001, working in various departments including Customer Billing, Automated Metering Infrastructure, Information Technology and Transmission Settlements. I have worked in the Rates and Regulatory Affairs department since January 2020.

Q. Does this conclude your testimony?

A. Yes.

Exhibits	**Description**
901	Proposed Tariff Changes
902	Estimated Impact of Proposed Changes on Customers
903	Rate Design
904	Allocation of Costs to Customer Classes
905	Streetlight and Area Lights
906	Schedule 50 Redline
907	Schedule 56 Redline
908	Rule C Redline

SCHEDULE 7
RESIDENTIAL SERVICE

PURPOSE

This schedule provides Standard and Optional Service choices for residential customers. Optional Services include Time-of-Day (TOD) , Peak Time Rebate, and Green Future^{SM} renewable portfolio options. **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

ENERGY PRICE PLANS (DEFAULT PLAN OR TOD) **(C)**

RESIDENTIAL SERVICE PRICE PLAN (DEFAULT PLAN)

This default plan is provided to Residential Customers who have not chosen the TOD portfolio option price plan. **(C)** **(C)**

Monthly Rate

The default plan is priced as the total of the following charges per Service Point (SP)*:

Basic Charge			
Single-Family Home	$15.00		**(I)**
Multi-Family Home	$12.00		
Transmission and Related Services Charge	0.890	¢ per kWh	
Distribution Charge	7.199	¢ per kWh	
Energy Charge	9.279	¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

SCHEDULE 7 (Continued)

TIME-OF-DAY (TOD) PORTFOLIO OPTION

This optional price plan provides TOD pricing for transmission and related services, distribution and energy and can apply to a whole premise or to plug-in electric vehicle charging only*. Enrollment is necessary.

Monthly Rate

Basic Charge			
Single-Family Home	$15.00		(I)
Multi-Family Home	$12.00		(I)
On-Peak Charge	40.990	¢ per kWh	(R)
Transmission and Related Services	2.580	¢ per kWh	(I)
Distribution	20.790	¢ per kWh	(R)
Energy	17.620	¢ per kWh	(I)
Mid-Peak Charge	16.990	¢ per kWh	(I)
Transmission and Related Services	0.930	¢ per kWh	(I)
Distribution	7.580	¢ per kWh	(I)
Energy	8.480	¢ per kWh	(R)
Off-Peak Charge	10.930	¢ per kWh	(I)
Transmission and Related Services	0.393	¢ per kWh	
Distribution	3.163	¢ per kWh	
Energy	7.374	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

On- and Off-Peak Hours

On-Peak	5:00 p.m. to 9:00 p.m. Monday-Friday
Mid-Peak	7:00 a.m. to 5:00 p.m. Monday-Friday;
Off-Peak	9:00 p.m. to 7:00 a.m. Monday-Friday;
	All day. Saturday, Sunday and holidays

Note: For Customers with Non-Network Meters, the time periods set forth above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November. Customers with Network Meters will observe the regular daylight-saving schedule.

Holidays are as follows: New Year's Day on January 1; Memorial Day, the last Monday in May; Independence Day on July 4; Labor Day, the first Monday in September; Thanksgiving Day, the fourth Thursday in November; and Christmas Day on December 25. If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

SCHEDULE 7 (Continued)

(D)
(M)

Plug-In Electric Vehicle (EV) Charging Option

A Residential Customer wishing to charge Electric Vehicles (EVs) may do so either as part of Whole Premises Service (default plan or the TOD portfolio option) or as a separately metered service billed under the TOD portfolio option. In such cases, the applicable basic, transmission and related services, distribution and energy charges will apply to the separately metered service as will all other adjustments applied to this schedule. Renewable Portfolio Options are also available under this EV charging option. (C) (C)

If the Customer chooses separately metered service for EV charging, the service shall be for the exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the Premises. Such service must be metered with a Network Meter as defined in Rule B for the purpose of load research, and to collect and analyze data to characterize EV use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

Special Conditions Pertaining to the Portfolio Option (including Whole Premise and EV Charging) (C)

1. Service may be terminated at the next regularly scheduled meter reading provided the Company has received two weeks' notice prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. Participation requires a one-year commitment by the Customer. Generally, if a Customer requests removal from the TOD option, the Customer will be required to wait 12 months before re-enrolling. However, a Customer may request to reinstate service within 90 days of termination, in which case the Portfolio Enrollment Charge will be waived. (C)

3. The Customer must take service at 120/240 volts or greater.

4. The Customer must provide the Company access to the meter monthly.

5. After a Customer's initial 12 months of service on the TOD option, the Company will calculate what the Customer would have paid under the default plan and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOD option exceeded the default plan Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount more than 10% either as a bill credit or refund check. No refund will be issued for Customers not meeting the 12-month requirement. (C) (C)

6. The Company may recover lost revenue from the TOD optional price plan through Schedule 105. (C)

(M)

SCHEDULE 7 (Continued)

(D)

Special Conditions Pertaining to the Portfolio Option (including Whole Premise and EV Charging) (Continued) (T)

7. Billing will begin for any Customer no later than the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date, assuming no meter exchange is required to enable the TOD option. (M) (C)

8. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons.

ADDITIONAL PORTFOLIO OPTIONS FOR ENERGY PRICE PLANS

PEAK TIME REBATE EVENT PARTICIPATION

Customers choosing the Peak Time Rebate (PTR) program are eligible to receive a rebate for reducing Energy use during Company-called events, relative to each Customer's baseline Energy use, as determined by the Company.

This option is available for enrollment to the first 160,000 Residential Customers. Customer enrollment will close once the program has 160,000 Residential Customers.

Monthly Rate

Customers enrolled in PTR will pay their energy price plan monthly rate – which includes Basic Charge, transmission and related services, and distribution charges. Energy Charges may also include the following PTR credit:

PTR Credit	100.00	¢ per kWh

To receive the PTR Credit, the Customer must reduce Energy use during a PTR Event. Such event will be a two- to five-consecutive-hour window between the hours of 7:00 AM to 11:00 AM or 3:00 PM to 9:00 PM. Events will not be called on holidays*

The PTR program has two event seasons: summer (the successive calendar months of June through September) and winter (successive calendar months of November through February). The Company will call PTR events only in event seasons. Prior to each season, the Company will remind the enrolled Customers that they are on the program, that they may participate in PTR events, and ways to be successful.

* Holidays are as follows: New Year's Day on January 1; Memorial Day, the last Monday in May; Independence Day on July 4; Labor Day, the first Monday in September; Thanksgiving Day, the fourth Thursday in November; and Christmas Day on December 25. If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday. (M)

SCHEDULE 7 (Continued)

ADDITIONAL PORTFOLIO OPTIONS FOR ENERGY PRICE PLANS (Continued) **(T)**

The Company initiates PTR events with an event notification to participating Customers the day prior to the PTR event. Participating Customers must choose at least one method for receipt of notification: email, text, or another available option. The Company will not call PTR events for more than two consecutive days. Reasons for calling events may include but are not limited to: Energy load forecasted to be in the top 1% of annual load hours, forecasted temperature above 90 or below 32, expected high generation heat rates and market power prices, and/or forecasted low or transitioning wind generation. **(M)**

Special Conditions Related to Peak Time Rebate Options

1. To be eligible for a PTR credit, the Customer must agree to receive PTR notifications.

2. The Customer may unsubscribe from the PTR event notification at any time. If the Customer unsubscribes, they will receive credit only for those events for which they are enrolled and receive notifications.

3. The PTR incentive may be provided in an on-bill credit on the Customer's next monthly billing statement or by check at the next billing statement after the event season ends.

4. Customers enrolled in Schedule 5 Direct Load Control are not eligible to participate in PTR on this schedule.

5. The Company will defer and seek recovery of all PTR costs not otherwise included in rates.

GREEN FUTURE RENEWABLE PORTFOLIO OPTIONS

Customers can add any of the following Green Future Renewable Portfolio options to any service described in this schedule: renewable fixed option, renewable usage option, and renewable habitat option adder (Habitat Support).

The Customer will be charged for the Green Future Renewable Portfolio option in addition to all other charges under this schedule for the term of enrollment in the Green Future Renewable Portfolio option.

Energy or Renewable Energy Certificates (RECs), as defined in Rule B of this tariff, will be acquired by the Company such that by March 31 of the succeeding year, the Company will have received sufficient RECs or renewable energy to meet the purchases by Customers. For the renewable fixed and renewable usage options, the Company is not required to own renewables or to acquire Energy from renewable resources simultaneously with Customer usage.

For purposes of these options, renewable resources include wind, solar, biomass, low impact hydro (as certified by the Low Impact Hydro Institute) and geothermal energy sources used to produce electric power. All RECs will be Green-e® Energy certified by the Center for Resource Solutions (CRS). **(M)**

SCHEDULE 7 (Continued)

RENEWABLE FIXED OPTION (M)

The Company will use funds received under this option to cover program costs and purchase 200 kWh of RECs and/or renewable energy per block enrolled in the renewable fixed option. All RECs purchased under this option will come from new renewable resources.

The Company will also place any funds not spent after covering program and REC costs received from Customers enrolled in this option in a renewable resources development and demonstration fund ("Renewable Development Fund" or "RDF"). See Special Conditions for additional details on the RDF.

Monthly Rate

Renewable Fixed Option	$1.88	per month per block

RENEWABLE USAGE OPTION

Amounts received from Customers under the renewable usage option will be used to cover program costs and acquire RECs and/or Energy, all of which will come from new renewable resources.

The Company will place any funds received from Customers enrolled in this option that are not spent after covering program and REC costs in a renewable resources development and demonstration fund ("Renewable Development Fund" or "RDF"). See Special Conditions for additional details on the RDF.

Monthly Rate

Renewable Usage Option	0.940	¢ per kWh in addition to Energy Charge

(M)

SCHEDULE 7 (Continued)

RENEWABLE HABITAT OPTION ADDER (HABITAT SUPPORT) **(M)**

The Company will distribute $2.50 per month as received from each Customer enrolled in habitat support to a nonprofit agency chosen by the Company who will use the funds for habitat restoration.

Available

Only Customers who are enrolled in a Green Future Renewable Portfolio option, described in this schedule, may choose habitat support.

Monthly Rate

Habitat Support	$2.50	per month

Special Conditions Related to Green Future Renewable Portfolio Options

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received two weeks’ notice prior to the meter read date. Absent the two-week notice, the termination will occur with the subsequent meter reading date.

2. The Company, in its discretion, may accept participation from accounts that have a time payment agreement in effect, or have received two or more final disconnect notices. However, the Company will not accept participation from customers that have been involuntarily disconnected in the last 12 months due to non-payment.

3. The Company will use reasonable efforts to ensure energy assistance dollars from the Oregon Low Income Home Energy Assistance Program (LIHEAP) and Oregon Energy Assistance Program (OEAP) assistance programs are not used to cover Green Future program participation during the time which participants receive these energy assistance funds. As such, PGE will unenroll Customers from the Green Future program if they receive energy assistance funds from LIHEAP and OEAP. If these energy assistance dollars are no longer applied to the bill, the Customer may re-enroll in the program subject to the above requirements.

4. The Company will use reasonable efforts to acquire renewable energy but does not guarantee the availability of renewable energy sources to serve Green Future Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer’s participation. **(M)**

SCHEDULE 7 (Concluded) **(T)**

Special Conditions Related to Green Future Renewable Portfolio Options (Continued) **(M)**

5. Amounts in the RDF will be disbursed by the Company to non-residential renewable resource demonstration projects or projects that commit to supply Energy according to a contractually established timetable. The Company will report to the Commission annually by March 15th, pursuant to Order No. 16-156, on collections and disbursements for the preceding calendar year. The annual report will include a list of projects that received or were allocated RDF funding.

6. Amounts placed in the RDF prior to July 6, 2016 will accrue interest at the Commission-authorized cost of capital until disbursed. Amounts placed in the fund on and after July 6, 2016 will accrue interest at the Commission-authorized rate for deferred accounts in amortization until disbursed. Amounts within the fund will be disbursed on a first-in-first-out basis. Once funds have been committed to projects, following the required OPUC review, they will be deemed disbursed. Funds deemed disbursed and still held by the Company, will accrue interest at the Commission-authorized rate for deferred accounts in amortization.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100. **(M)**

SCHEDULE 15
OUTDOOR AREA LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer notifies the Company of the burn-out.

MONTHLY RATE

Included in the service rates for each installed luminaire are the following pricing components:

Transmission and Related Services Charge	0.511	¢ per kWh	**(I)**
Distribution Charge	7.196	¢ per kWh	**(I)**
Cost of Service Energy Charge	6.697	¢ per kWh	**(I)**

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Cobrahead					
Mercury Vapor	175	7,000	66	$14.68[2]	(I)
	400	21,000	147	26.99[2]	
	1,000	55,000	374	59.57[2]	
HPS	70	6,300	30	10.40[2]	
	100	9,500	43	11.45	
	150	16,000	62	14.27	
	200	22,000	79	17.23	
	250	29,000	102	20.19	
	310	37,000	124	23.47[2]	
	400	50,000	163	29.10	
Flood, HPS	100	9,500	43	11.33[2]	
	200	22,000	79	18.68[2]	
	250	29,000	102	22.15	
	400	50,000	163	30.84	
Shoebox, HPS (bronze color,	70	6,300	30	10.20	
flat lens or drop lens, multi-volt)	100	9,500	43	12.66	
	150	16,500	62	15.86	
Special Acorn Type, HPS	100	9,500	43	17.33	
HADCO Victorian, HPS	150	16,500	62	20.09	
Early American Post-Top, HPS					
Black	100	9,500	43	12.97	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	$16.32	**(I)**
	175	12,000	71	16.18	
Flood, Metal Halide	350	30,000	139	28.59	
	400	40,000	156	28.67	
Flood, HPS	750	105,000	285	51.80	
HADCO Independence, HPS	100	9,500	43	16.99	
HADCO Techtra, HPS	100	9,500	43	24.12	
	150	16,000	62	27.70	**(I)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire(1)	
Acorn LED	>35-40	3,262	13	$15.51	**(I)**
	>40-45	3,500	15	15.80	
	>45-50	5,488	16	13.33	
	>50-55	4,000	18	16.23	
	>55-60	4,213	20	16.52	
	>60-65	4,273	21	16.66	
	>65-70	4,332	23	16.58	
	>70-75	4,897	25	17.24	**(I)**
	>91-100	8,100	32	18.29	**(N)**
HADCO LED	70	5,120	24	20.69	**(I)**
Roadway LED	>20-25	3,000	8	6.42	**(I)**
	>25-30	3,470	9	6.57	
	>30-35	2,530	11	7.12	
	>35-40	4,245	13	7.14	
	>40-45	5,020	15	7.60	
	>45-50	3,162	16	7.73	
	>50-55	3,757	18	8.30	
	>55-60	4,845	20	8.32	
	>60-65	4,700	21	8.46	
	>65-70	5,050	23	9.50	
	>70-75	7,640	25	9.82	
	>75-80	8,935	26	9.97	
	>80-85	9,582	28	10.25	
	>85-90	10,230	30	10.54	
	>90-95	9,928	32	10.83	
	>95-100	11,719	33	10.97	
	>100-110	7,444	36	11.21	
	>110-120	12,340	39	11.84	
	>120-130	13,270	43	12.41	
	>130-140	14,200	46	13.24	
	>140-150	15,250	50	15.79	
	>150-160	16,300	53	16.22	
	>160-170	17,300	56	16.66	
	>170-180	18,300	60	16.89	
	>180-190	19,850	63	17.66	
	>190-200	21,400	67	17.40	**(I)**
	>200-210	27,033	70	17.91	**(N)**
	>210-220	28,535	74	19.27	**(N)**
	>220-230	30,017	77	19.70	**(N)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire(1)	
Roadway LED (Cont)	>230-240	30,800	81	$ 20.28	(N)
	>240-250	31,507	84	21.21	(N)
Pendant LED (Non-Flare)	36	3,369	12	15.97	(R)
	53	5,079	18	17.97	(R)
	69	6,661	24	18.61	(R)
	85	8,153	29	19.89	(R)
Pendant LED (Flare)	>35-40	3,369	13	15.53	(R)
	>40-45	3,797	15	16.68	(I)
	>45-50	4,438	16	16.82	(I)
	>50-55	5,079	18	19.88	(I)
	>55-60	5,475	20	16.54	(R)
	>60-65	6,068	21	20.31	(I)
	>65-70	6,661	23	19.71	(I)
	>70-75	7,034	25	17.26	(R)
	>75-80	7,594	26	20.37	(I)
	>80-85	8,153	28	20.65	(I)
CREE XSP LED	>20-25	2,529	8	6.58	(I)
	>30-35	4,025	11	7.01	(I)
	>40-45	3,819	15	7.59	(I)
	>45-50	4,373	16	7.79	(I)
	>55-60	5,863	20	8.37	(I)
	>65-70	9,175	23	9.35	(I)
	>90-95	8,747	32	10.65	(I)
	>130-140	18,700	46	14.18	(I)
Post-Top, American Revolution LED	>30-35	3,395	11	8.63	(R)
	>45-50	4,409	16	9.35	(R)
Flood LED	>80-85	10,530	28	11.36	(I)
	>120-130	16,932	43	14.07	(I)
	>180-190	23,797	63	18.16	(I)
	>321-330	46,802	112	29.67	(N)
	>331-340	48,692	116	30.25	(N)
	>341-350	50,145	119	30.68	(N)
	>351-360	51,598	123	31.26	(N)
	>370-380	48,020	127	31.80	(I)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Light Poles[(2)]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$6.64	(I)
	40 to 55	7.82	
Wood, Painted for Underground	35 or less	6.57[(3)]	
Wood, Curved Laminated	30 or less	7.73[(3)]	
Aluminum, Regular	16	5.07	
	25	9.42	
	30	10.81	
	35	12.52	
Aluminum, Fluted Ornamental	14	8.93	
Aluminum, Fluted Ornamental	16	9.27	
Aluminum Davit	25	10.05	
	30	11.32	
	35	12.95	
	40	16.62	
Aluminum Double Davit	30	12.56	
Aluminum, Smooth Techtra Ornamental	18	19.11	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No pole charge for luminaires placed on existing Company-owned distribution poles.
(3) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Fiberglass Fluted Ornamental; Black	14	$11.77	(I)
Fiberglass, Regular			
Black	20	5.48	
Gray or Bronze	30	8.91	
Black, Gray, or Bronze	35	8.70	
Fiberglass, Anchor Base, Gray or Black	35	11.87	
Fiberglass, Anchor Base (Color may vary)	25	10.55	
	30	12.89	
Fiberglass, Direct Bury with Shroud	18	7.43	
Aluminum, Regular with Breakaway Base	35	17.93	
Aluminum, Double-Arm, Smooth Ornamental	25	15.05	
Aluminum, Smooth, Black, Pendant	23	18.30	(I)
Aluminum, Regular with Breakaway Base	25	16.56	(N)
	30	16.90	(N)

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge			
Single Phase Service	$24.00		(I)
Three Phase Service	$33.00		(I)
Transmission and Related Services Charge	0.718	¢ per kWh	(I)
Distribution Charge			
First 5,000 kWh	7.395	¢ per kWh	(I)
Over 5,000 kWh	3.474	¢ per kWh	(I)
Energy Charge Options			
Standard Service	8.256	¢ per kWh	(I)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	14.586	¢ per kWh	(I)
Mid-Peak Period	8.256	¢ per kWh	(I)
Off-Peak Period	4.862	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

DAILY PRICE

The Daily Price, applicable with Direct Access Service, is available to those Customers who were served under Schedule 532 and subsequently returned to this schedule before meeting the minimum term requirement of Schedule 532. The Customer will be charged the Daily Price charge of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index)
- plus 0.315¢ per kWh for wheeling **(R)**
- times a loss adjustment factor of 1.0640

If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported.

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

PLUG-IN ELECTRIC VEHICLE (EV) TOU OPTION

A small Nonresidential Customer wishing to charge EV’s may do so either as part of an integrated service (Standard service or TOU service) or as a separately metered service billed under the TOU option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule. Renewable Portfolio Options are also available under this EV option.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

SCHEDULE 32 (Continued)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. Customers must enroll to receive service under any portfolio option. Customers may initially enroll or make one portfolio change per year without incurring the Portfolio Enrollment Charge as specified in Schedule 300. **(T)(M)**

2. Unmetered service may be provided under this schedule to fixed loads with fixed periods of operation, including, but not limited to, telephone booths and television amplifiers, which are unmetered for the convenience and mutual benefit of the Customer and the Company. The average monthly usage to be used for billing will be determined by test or estimated from equipment ratings and will be mutually agreed upon by the Customer and the Company. **(T)** **(M)**

Pertaining to Direct Access

1. Customers served under this schedule may at any time notify the Company of their intent to choose Direct Access Service. Notification must conform to the requirements established in Rule K.

Pertaining to Renewable Portfolio Options

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. The Company, in its discretion, may accept enrollments on accounts that have a time payment agreement in effect, or have received two or more final disconnect notices. However, the Company will not accept enrollments from customers that have been involuntarily disconnected in the last 12 months due to non-payment.

SCHEDULE 38
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers: 1) served at Secondary Demand Voltage whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW; or 2) who were receiving service on Schedule 38 as of December 31, 2015. or 3) for Customers taking service on the separately metered Plug-In Electric Vehicle Time of Day option whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with 7 months or less of service has not had a Demand exceeding 4,000 kW.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge			
Single Phase Service	$50.00		(I)
Three Phase Service	$60.00		(N)
Transmission and Related Services Charge	0.705	¢ per kWh	(I)
Distribution Charge	9.515	¢ per kWh	(I)
Energy Charge**			
On-Peak Period	9.527	¢ per kWh	(I)
Mid-Peak Period	8.527	¢ per kWh	(N)
Off-Peak Period	6.527	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Energy On-peak hours are between 4:00 p.m. and 10:00 p.m. Monday through Friday, Mid-peak hours are between Monday through Friday 6:00 a.m. to 4:00 p.m. and Saturday 6:00 a.m. to 10:00 p.m. Off-peak hours are Monday through Saturday 10:00 p.m. to 6:00 a.m. and all day Sunday. (C) | (C)

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

(M)

SCHEDULE 38 (Continued)

REACTIVE DEMAND

(M)

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

(M)

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

November Election Window

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, https://portlandgeneral.com

DIRECT ACCESS DEFAULT SERVICE

A Customer returning to Schedule 38 service before completing the term of service specified in Schedule 538, must be billed at the Daily Price for the remainder of the term. This provision does not eliminate the requirement to receive service on Schedule 81 when notice is insufficient. The Daily Price under this schedule is as follows:

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.315¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. (R)

(M)

SCHEDULE 38 (Concluded)

DIRECT ACCESS DEFAULT SERVICE (Continued) **(T)**
Daily Price Option (Continued) **(T)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors: **(M)**

Secondary Delivery Voltage	1.0640

(M)

PLUG-IN ELECTRIC VEHICLE (EV) TIME OF DAY OPTION

A large Nonresidential Customer wishing to charge EV's may do so either as part of an integrated service or as a separately metered service billed under the TOU Option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

Pertaining to Optional Time of Day Standard Service

1. Service under this schedule will begin on the first day of the Customer's regularly scheduled Billing Period.

2. In no case will the Company refund a Customer by retroactively adjusting the rate at which service was billed prior to the date the Customer begins service on this schedule.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 47
SMALL NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge			
Summer Months**	$39.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.757	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand***	14.768	¢ per kWh	(I)
Over 50 kWh per kW of Demand	12.768	¢ per kWh	(I)
Energy Charge	9.348	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Large Nonresidential Customer is defined as having a monthly Demand exceeding 30 kW at least twice within the preceding 13 months, or with seven months or less of service having exceeding 30 kW once.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge			
Summer Months**	$60.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.708	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand***	13.434	¢ per kWh	(I)
Over 50 kWh per kW of Demand	11.434	¢ per kWh	(I)
Energy Charge	9.766	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 30 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 50
RETAIL ELECTRIC VEHICLE (EV) CHARGING

PURPOSE

This retail Electric Vehicle (EV) charging schedule is a supplemental service that governs the use of PGE's charging network for EVs. This schedule does not impact, replace, or otherwise modify any base retail service under which a customer is currently served by PGE. This schedule is designed solely for the retail sale of electricity as a transportation fuel.

DEFINITIONS

Direct Current Quick Chargers (DCQC) or Direct Current Fast Chargers (DCFC) – individual chargers that provide service at approximately 50 kW of peak demand or greater.

Electric Avenue Sites – Stations in PGE's service area that are listed as part of Electric Avenue on portlandgeneral.com.

EV User – An EV driver or operator who uses the PGE charging Station. This does not have to be a PGE customer.

Holidays – refers to New Year's Day (December 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November, and Christmas Day (December 25). If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

Idle Fee – refers to the fee charged to customers if their vehicle remains plugged into a charger after a 10-minute grace period when their vehicle has finished charging. **(N)**

Income Qualified – Customers who qualify for PGE's Income Qualified Bill Discount (IQBD) program. **(N)**

Level 2 Chargers - individual chargers that are capable of providing service at approximately 7 kW.

Off-Peak – refers to all other hours outside of the On-Peak period.

On-Peak – refers to the hours of 5 PM to 9 PM on weekdays, excluding holidays. **(C)**

Session – each unique charging event in which a customer connects a vehicle to a PGE charger.

Station – the location of a PGE charging facility, consisting of one or more DCQC and/or Level 2 Chargers.

(M)

SCHEDULE 50 (Concluded)

AVAILABLE **(M)**

The service described in this schedule is available through a point-of-sale transactionand is intended for use at PGE's EV charging Stations. **(C)** **(C)**

This schedule is not available for any use other than the purchase of retail electricity as a transportation fuel. **(M)**

APPLICABLE

This schedule is available to all EV Users of PGE's EV charging Stations.

RATE

Pricing is as follows: **(C)**

	Off-Peak Fee (all hours)	**On-Peak Charging Price**	**Idle Fee**
Direct Current Fast Charger	$$0.30 per kWh	$0.58 per kWh	$0.40 per minute after 10 minutes
Level 2 Charger	$0.12 per kWh	$0.40 per kWh	$0.10 per minute after 10 minutes
Income Qualified DCFC Charger*	$0.24 per kWh	$0.52 per kWh	$0.40 per minute after 10 minutes
Income Qualified Level 2 Charger	$0.10 per kWh	$0.32 per kWh	$0.10 per minute after 10 minutes

(D)

* Income qualified customers must qualify by entering the phone number associated with their PGE account into the charging station app or by calling the charging station's customer service. Customers must already be enrolled in the IQBD program. **(C)**

(D)

Payment will be made via credit card or other applicable payment method at the PGE charging Station, via the charging station's mobile app, or via calling the charging station's customer service. **(C)** **(C)**

SPECIAL CONDITIONS

1. This schedule is designed for retail service to drivers or operators of EVs. EV User-owned EV chargers are not eligible for service under this retail charging rate. **(D)**

2. EV Users may not request service under this schedule for any purpose other than the purchase of electricity from PGE to fuel the customer's vehicle(s) at PGE's EV charging Stations.

SCHEDULE 56
COMMERCIAL ELECTRIC VEHICLE MAKE-READY PILOT AND TRANSPORTATION ELECTRIFICATION LINE EXTENSION ALLOWANCE (C) (C)

PURPOSE

This Commercial Electric Vehicle (EV) Make-Ready Pilot provides eligible Fleet and Non-Fleet Customers with incentives to install Electric Vehicle charging infrastructure to support fleet and personal electric vehicles at fleet, commercial, workplace, and multifamily sites. The overarching goals of the pilot for both Fleet and Non-Fleet Customers are to:

- Evaluate the methods and incentives used to support both Fleet and Non-Fleet Customers' electric transportation transition;
- Create a network of demand side resources to reduce the costs of serving EV loads by supporting efficient grid operation and future renewables integration; and
- Generate empirical data that can be used to inform existing utility analyses, support customers transitioning to electric vehicles, and develop future products and programs.

The primary goals of the pilot for Fleet Customers are to:

- Enable and support the electrification of commercial, public (municipal, county, state, federal), school, non-profit and transit fleets by reducing customer cost and complexity associated with transitioning to electric fuel;
- Better understand the Fleet Customer and barriers and opportunities in the fleet electrification market; and
- Identify areas for utility process improvement with respect to fleet electrification.

The primary goals of the pilot for Non-Fleet Customers are to:

- Support the equitable electric transportation transition at commercial, workplace, and multifamily locations by reducing costs and complexity for property owners;
- Gain insight and information to better understand the barriers for Non-Fleet Customers and users of public and semi-public charging infrastructure; and
- Identify areas of utility process improvement for non-fleet commercial electrification and make ready infrastructure deployment.

The Fleet Transportation Line Extension Allowance (TLEA) provides eligible Fleet Customers a monetary allowance to aid in the installation of EV make-ready infrastructure to enable and support the electrification of commercial, public (municipal, county, state, federal), school, non-profit and transit fleets by reducing customer cost and complexity associated with transitioning to electric fuel. The Fleet TLEA replaces the Fleet Commercial Electric Vehicle Make-Ready Pilot upon full reservation of all funds available in the pilot. (N) (N)

AVAILABLE

In all territory served by PGE.

(M)

SCHEDULE 56 (Continued)

APPLICABLE

(M)

This Tariff is applicable to nonresidential customers within PGE's service area. **(C)(M)**

DEFINITIONS

(D)

Electric Vehicle Supply Equipment (EVSE aka Charger) – the device, including the cable(s), coupler(s), and other associated hardware, installed for the purpose of transferring electricity between the Make-Ready Infrastructure and the EV. **(C)** **(C)**

Electric Vehicle Service Provider (EVSP) – provider of the software platform that manages and collects data from the EVSE(s). **(C)** **(C)**

Fleet Customer – A nonresidential customer installing EVSEs at a fleet site for use by EVs owned or leased by Nonresidential Customers. **(C)** **(C)**

Line Extension – has the same meaning as set forth in Rule I.

Line Extension Allowance – has the same meaning as set forth in Rule I and is calculated per Schedule 300.

Line Extension Cost – has the same meaning as set forth in Rule I.

Make-Ready Cost – estimated actual cost of the acquisition, construction or installation, including costs for upgrades for the Make-Ready Infrastructure. and Line Extension, excluding those accounted for in the Line Extension Cost. **(C)** **(C)**

Make-Ready Infrastructure – the infrastructure at the Site that delivers electricity from the Service Point to the EVSE, including any panels, stepdown transformers, conduit, wires, connectors, meters, and any other necessary hardware. **(C)** **(C)**

Make-Ready Port – Make-Ready Infrastructure constructed in a way that supports the future installation of EVSEs with the corresponding number of ports. For example, a site constructed with Make-Ready Infrastructure for five dual-port EVSEs would have ten (10) Make-Ready Ports.

Non-Fleet Customer – A nonresidential customer installing EVSEs at commercial, workplace, multifamily, or other sites for use by EVs owned or leased by Residential Customers.

Operational – an EVSE installed at the Site is able to transfer energy between the Site wiring and the EV, with any applicable payment methods (e.g., credit card, phone app, subscription card), and transmitting operational data (e.g. energy usage, session start/end times) to the Qualified EVSP.

(M)

SCHEDULE 56 (Continued)

DEFINITIONS (Continued)

Qualified EVSE –EVSE that is on PGE's qualified products list. **(C)(M)**

Qualified Level 2 EVSE – An EVSE on PGE's qualified products list that provides Alternating Current (AC) electricity to the EV at 208 or 240 volts. **(C)**

Qualified EVSP – EVSP(s), that is on PGE's qualified products list. **(C)(M)**

Qualified Service Schedule – list of qualified service schedules, including Schedules 32, 38, 83, 85, and 89. The list of qualified service schedules may be expanded to include new rates in the future.

Service Point – has the same meaning as set forth in Rule B.

Site – has the same meaning as set forth in Rule B.

Site Activation Date – the date that PGE determines the first EVSE at the Site is installed and **(N)**
Operational. PGE will provide Customer with written notice of the Site Activation Date. **(N)**

Site Owner – entity holding title to the Site.

ELIGIBILITY

Eligible Fleet Customers are nonresidential customers that use or operate fleets (including, but not limited to, commercial, non-profit, public, school or transit fleets) within PGE's service territory installing a minimum of 70 kW of EV charging. Eligible Fleet Customers must own or lease the Site.

Eligible Non-Fleet Customers are nonresidential customers that are installing a minimum of 8 Qualified Level 2 EVSE Ports at existing commercial, workplace, or multi-family properties and are intended to be used by EVs owned or leased by Residential Customers. Eligible Non-Fleet Customers must own, lease, or manage the Site, and not have any active construction occurring at the site at the time of installation.

Eligible Fleet TLEA Customers are Fleet Customers who own, lease, or manage the Site and **(N)**
participate in the TLEA with a minimum 10-year total Energy Commitment of 400,000 kWh. **(N)**

ENROLLMENT

Commercial Electric Vehicle Make-Ready Pilot: **(C)**

The customer enrollment period for eligible Fleet Customers will be open through December 2025, or until available funds for the pilot have been fully reserved. Eligible customers may apply at PortlandGeneral.com and enroll by signing a participation agreement.

(M)

SCHEDULE 56 (Continued)

ENROLLMENT (Continued) **(T)**

The enrollment period for eligible Non-Fleet Customers will be open through December 2025, or until available funds for the pilot have been fully reserved. Eligible customers may apply at PortlandGeneral.com and enroll by signing a participation agreement. **(M)** **(M)**

Upon full reservation of the fleet incentives in the commercial electric vehicle make-ready pilot, eligible customers may apply for the Fleet TLEA at PortlandGeneral.com and enroll by signing a participation agreement and meeting other program requirements. **(N)** **(N)**

INCENTIVE **(M)**

Fleet Customers will pay for the Make-Ready Cost, less a custom incentive. The custom incentive will be calculated as the lower of the following amounts:

- Estimated Year 5 EVSE annual energy use x Line Extension Allowance x 7.5; or
- The participant's Make-Ready Costs; or
- $400,000. **(M)**

Non-Fleet Customers will pay for Make-Ready Cost and Line Extension costs less an incentive not to exceed $17,000 per Make Ready Port. Non-Fleet Customers receiving the incentive cannot also receive a Line Extension Allowance for the same project. The incentive will be calculated as the lower of the following amounts:

- $17,000 per Make-Ready Port;
- The participant's Make-Ready Costs; or
- $204,000.

Fleet TLEA Customers will pay for the Make-Ready Cost and Line Extension Cost less an incentive. Fleet TLEA Customers receiving the incentive cannot also receive a Line Extension Allowance for the same project. The incentive will be calculated as the lower of the following amounts: **(N)**

- Committed 10 year total kWh × service schedule Line Extension Allowance × 1.4
- The participant's Line Extension Cost plus Make-Ready Cost
- $450,000 **(N)**

SPECIAL CONDITIONS

1. Participation in this tariff is not mandatory to install EV charging equipment. **(C)**

2. Any chargers installed as a part of this tariff must receive service on one of PGE's Standard Service Schedules. The customer's charges for electricity service under any of PGE's Standard Service or Direct Access Service schedules are not changed or affected in any way by participating in this schedule and are due and payable as specified in those schedules. **(C)**

(M)

SCHEDULE 56 (Continued) **(T)**

SPECIAL CONDITIONS (Continued)

3. PGE will locate, design, install, own, operate and maintain the Make-Ready Infrastructure. For Fleet Customers, EVSE(s) will be separately metered from any other load at the Site. EVSE(s) may be separately metered at Non-Fleet Customer sites. **(C)(M)**

4. The Site Owner may be required to grant an easement to PGE to maintain PGE-owned facilities.

5. If the final design of the Make-Ready Infrastructure is estimated to cost in excess of $15,000, PGE may require the customer to submit a deposit prior to proceeding to final design and enrollment. The deposit will be the amount of the estimated final design costs and will be applied to the Make-Ready Costs or refunded upon the participating customer's enrollment in the Pilot. If the customer does not enroll, the deposit will not be refunded.

6. If the final design of the Make-Ready Infrastructure has been completed and the Customer does not enroll in this tariff, the Customer may be required to reimburse PGE for final design costs and any other associated expenses that PGE incurs due to the cancellation of the project. **(C)**

7. If the participating Fleet Customer's custom incentive is in excess of $250,000, the participating Fleet Customer agrees that PGE may verify its creditworthiness at any time and seek financial security to ensure the participating Fleet Customer is able to meet its obligations as set forth in the participation agreement. **(M)**

8. The participating Fleet Customer is responsible for the procurement and installation of at least one new Qualified EVSE(s) within 6 months of PGE's completion of the Make-Ready Infrastructure. The participating Non-Fleet Customer is responsible for the procurement and installation of all Qualified Level 2 EVSE(s) within 12 months of PGE's completion of the Make-Ready Infrastructure.

9. The participating customer must maintain the EVSE(s) on a Qualified Service Schedule for 10 years following the Site Activation Date. **(C)**

10. The participating customer will ensure the EVSE(s) remain Qualified EVSE(s) and Operational for 10 years following the Site Activation Date. **(C)**

11. The participating Fleet Customer will adhere to an energy usage plan that sets forth the minimum amount of energy the participating customer commits to using over the 10 years following the Site Activation Date, but in no event will the minimum energy usage amount be less than the Estimated Year 5 energy use x 6. The participating Fleet TLEA Customer will adhere to an energy usage plan that sets forth the minimum amount of energy the participating customer commits to using over the 10 years following the Site Activation Date. **(C)** **(C)**

(M)

SCHEDULE 56 (Concluded)

SPECIAL CONDITIONS (Continued)

12. Fleet and Non-Fleet Customers participating in the Pilot will authorize and require the Qualified EVSP to provide operational data (e.g. charging session data, energy interval data) to PGE, and agree to allow PGE and its agents and representatives to use data gathered as part of the pilot in regulatory reporting, ordinary business use, industry forums, case studies or other similar activities, in accordance with applicable laws and regulations and to participate in PGE-led research such as surveys. **(C)(M)** **(C)**

13. If the Site changes ownership or lesseeship, participation in this tariff may be assumed by the new owner or lessee if it is willing to meet the requirements. The participating Fleet Customer will be responsible for any pro-rata reimbursement for estimated minimum usage deficiencies between the participating customer's original energy usage plan and the new customer's energy usage plan. **(C)** **(C)**

14. In the event the participating customer breaches or terminates the participation agreement, the participating customer will reimburse PGE the pro-rata value of the custom incentive, calculated over the 10-year term. **(M)**

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,190.00	$4,140.00	$5,860.00	(I)
Transmission and Related Services Charge				
per kW of monthly Peak Demand**	$2.78	$2.75	$2.70	(I)(C)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$2.04	$2.02	$2.00	(I)
Over 4,000 kW	$1.73	$1.71	$1.69	(I)
per kW of monthly Peak Demand**	$1.73	$1.71	$1.69	(I)(C)
Generation Contingency Reserves Charges				
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.244 ¢	0.241 ¢	0.238 ¢	(I)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.
** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. (N)

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Firm Electricity Price Index (Powerdex-Mid-C Hourly Firm Index) plus 0.315¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, **(R)**
plus losses.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)
Unscheduled Energy (Continued)

If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported. **(C)**

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. **(C)**

The Company may request that a Customer taking Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

LOSSES

Losses will be included by multiplying the applicable Energy Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:*

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Transmission and Related Services Charge				
per kW of Daily Economic Replacement Power (ERP) Peak Demand per day	$0.083	$0.082	$0.080	(C)
Daily ERP Demand Charge				
per kW of Daily ERP Demand during Peak Demand hours per day**	$0.059	$0.058	$0.005	(C)
Transaction Fee				
per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	
Energy Charge*				
per kWh of ERP	See below for ERP Pricing			

* See Schedule 100 for applicable adjustments.
** Peak Demand hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. (C)
(C)

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ENF Options for ERP (Continued)

The Daily ENF pre-scheduling protocols will conform to the standard practices, applicable definitions, requirements and schedules of the WECC. Pre-Schedule Day means the trading day immediately preceding the day of delivery consistent with WECC practices for Saturday, Sunday, Monday or holiday deliveries.

ERP Pricing

The following ERP Energy Charges are applied to the applicable hourly ENF and summed for the hours for the monthly billing:

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.315¢ per kWh for wheeling, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported. **(R)**

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.315¢ per kWh for wheeling, plus losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer's submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place. **(R)**

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.315¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. **(R)**

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing (Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

Peak hours (Heavy Load Hours, HLH) are between 6:00 a.m. and 10:00 p.m. PPT (hours ending 0700 through 2200), Monday through Saturday. **(C)** **(C)**

Losses will be included by multiplying the ERP Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer’s Schedule 75 Baseline Energy.

IMBALANCE ENERGY SETTLEMENT

Imbalance Settlement Amounts are bill credits or charges resulting from hourly Imbalance Energy multiplied by the applicable hourly Settlement Price and summed for all hours in the billing period. Imbalance Energy is the kWh amount determined hourly as the deviation between Actual Energy for such hour and the ENF for such hour (i.e., Imbalance Energy = Actual Energy less ENF).

For any Imbalance Energy in any hour up to 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive Imbalance Energy (where Customer receives more ERP than the ENF), the Imbalance Energy multiplied by the Settlement Price of the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 0.315¢ per kWh for wheeling, plus losses. **(R)**
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index plus 0.315¢ per kWh for wheeling, plus losses. **(R)**

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

For any Imbalance Energy in any hour in excess of 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 10%, plus 0.315¢ per kWh for wheeling, plus losses. **(R)**

For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index, less 10%, plus 0.315¢ per kWh for wheeling, **(R)** plus losses.

The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule N Curtailment Plan and Rule C (Section 2).

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (ICE-Mid-C Firm Index) plus 0.315¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. **(R)**

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

Losses will be included by multiplying the Energy Charge Daily Rate by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. Service under this Schedule is available for Secondary Delivery Voltage only.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge		
Single Phase Service	$50.00	(I)
Three Phase Service	$60.00	(I)
Transmission and Related Services Charge		
per kW of monthly Peak Demand****	$2.78	(I)(C)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$6.31	(I)
Over 30 kW	$6.21	(I)
per kW of monthly Peak Demand****	$1.73	(I)(C)
Energy Charge		
On-Peak Period per kWh***	6.344 ¢	(I)
Mid-Peak Period per kWh	5.544 ¢	(N)
Off-Peak Period per kWh***	4.344¢	(I)
Generation Demand Charge		
per kW of monthly Peak Demand	$9.34	(I)(C)
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	1.344 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.

*** Energy On-peak hours are between 4:00 p.m. and 10:00 p.m. Monday through Friday, Mid-peak hours are between Monday through Friday 6:00 a.m. to 4:00 p.m. and Saturday 6:00 a.m. to 10:00 p.m. Off-peak hours are Monday through Saturday 10:00 p.m. to 6:00 a.m. and all day Sunday. (N)–(N)

**** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. (C)

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.315¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0640

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer’s Electricity usage will be billed as 18% on-peak, 45% mid-peak and 37% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage. **(C)**

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 83 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 85
LARGE NONRESIDENTIAL
STANDARD SERVICE
(201 – 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Secondary Delivery Voltage Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. To each Primary Delivery Voltage Large Nonresidential Customer whose Demand has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$880.00	$750.00	(I)
Transmission and Related Services Charge			
per kW of monthly Peak Demand****	$2.78	$2.75	(I)(C)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.47	$3.43	(I)
Over 200 kW	$3.37	$3.33	(I)
per kW of monthly Peak Demand****	$1.73	$1.71	(I)(C)
Energy Charge			
On-Peak Period per kWh***	6.155 ¢	6.100 ¢	(I)
Mid-Peak Period per kWh	5.355 ¢	5.300 ¢	(N)
Off-Peak Period per kWh***	4.155 ¢	4.100 ¢	(I)
Generation Demand Charge			
per kW of monthly Peak Demand****	$10.62	$10.50	(I)(C)
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.288 ¢	0.285 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.
***Energy On-peak hours are between 4:00 p.m. and 10:00 p.m. Monday through Friday, Mid-peak hours are between Monday through Friday 6:00 a.m. to 4:00 p.m. and Saturday 6:00 a.m. to 10:00 p.m. Off-peak hours are Monday through Saturday 10:00 p.m. to 6:00 a.m. and all day Sunday. (N)
****Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. (C)

SCHEDULE 85 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.315¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer’s Electricity usage will be billed as 18% on-peak, 45% mid-peak and 37% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage. **(C)**

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 85 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate Schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 89
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,190.00	$4,140.00	$5,860.00	**(I)**
Transmission and Related Services Charge				
per kW of monthly Peak Demand	$2.78	$2.75	$2.70	**(I)(C)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$2.04	$2.02	$2.00	**(I)**
Over 4,000 kW	$1.73	$1.71	$1.69	**(I)**
per kW of monthly Peak Demand	$1.73	$1.71	$0.13	**(I)(C)**
Energy Charge (per kWh)				
On-Peak Period***	8.553 ¢	8.473 ¢	8.391 ¢	**(I)**
Mid-Peak Period	7.753 ¢	7.673 ¢	7.591 ¢	**(N)**
Off-Peak Period***	6.553 ¢	6.473 ¢	6.391 ¢	**(I)**
See below for Daily Pricing Option description.				
System Usage Charge				
per kWh	0.244 ¢	0.241 ¢	0.238 ¢	**(I)**

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.

*** Energy On-peak hours are between 4:00 p.m. and 10:00 p.m. Monday through Friday, Mid-peak hours are between Monday through Friday 6:00 a.m. to 4:00 p.m. and Saturday 6:00 a.m. to 10:00 p.m. Off-peak hours are Monday through Saturday 10:00 p.m. to 6:00 a.m. and all day Sunday. **(N)**

*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. **(C)**

SCHEDULE 89 (Continued)

MONTHLY RATE (Continued)
Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.315¢ per kWh for wheeling, plus **(R)** losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 90
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account.

MONTHLY RATE1st

The sum of the following charges per Service Point (SP)*:

	Delivery Voltage		
	Primary	Subtransmission	
Basic Charge	$18,500.00	$18,500.00	(I)
Transmission and Related Services Charge per kW of monthly On-Peak Demand	$2.75	$2.70	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$2.05	$2.05	(I)
Over 4,000 kW	$1.74	$1.74	
per kW of monthly on-peak Demand	$1.71	$0.13	
Energy Charge (per kWh)			
Usage (30MWa – 250MWa)			
On-Peak Period***	7.800¢	7.673¢	
Off-Peak Period***	6.300¢	6.081¢	
Usage (greater than 250MWa)			
On-Peak Period***	7.309¢	7.227¢	
Off-Peak Period***	5.809¢	5.727¢	
System Usage Charge			
Usage (30MWa – 250MWa) per kWh	0.242¢	0.242¢	
Usage (greater than 250MWa) per kWh	0.242¢	0.242¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.
*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 90 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.315¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 91 (Continued)

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.511 ¢ per kWh	(I)
Distribution Charge	7.196 ¢ per kWh	
Energy Charge		
Cost of Service Option	6.697 ¢ per kWh	(I)

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.315¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. (R)

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0640.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price Option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING

High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Cobrahead Power Doors **	100	9,500	43	*	*	**(C)**
						(D)
	400	50,000	163	*	*	**(C)**
Cobrahead	70	6,300	30	$6.16	$1.16	**(I)(R)**
	100	9,500	43	5.34	1.08	**(I)(R)**
	150	16,000	62	*	1.09	**(R)**
	200	22,000	79	*	1.14	**(C)(R)**
	250	29,000	102	*	1.13	**(C)(R)**
	400	50,000	163	5.70	1.12	**(I)(R)**
Flood	250	29,000	102	*	*	**(C)**
	400	50,000	163	*	*	**(C)**
Early American Post-Top	100	9,500	43	*	1.24	**(C)(R)**
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	*	1.15	**(C)(R)**
	100	9,500	43	*	1.21	**(R)**
	150	16,000	62	*	1.26	**(R)**

* Not offered.
** Service is only available to Customers with total power door luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black, Bronze, or Gray	20	$5.69	$0.19	**(I)**
Fiberglass, Black or Bronze	30	9.26	0.31	**(I)**
Fiberglass, Gray	30	9.26	0.31	**(I)**
Fiberglass, Smooth, Black or Bronze	18	6.09	0.20	**(I)**
Fiberglass, Regular Black, Bronze, or Gray	18	5.13	0.17	**(I)**
	35	8.98	0.30	**(I)**
Aluminum, Regular with Breakaway Base	25	16.56	0.55	**(N)**
	30	16.90	0.56	**(N)**
	35	18.28	0.60	**(I)**
Aluminum, Smooth, Black, Pendant	23	18.65	0.61	**(I)**

SCHEDULE 91 (Continued)

RATES FOR STANDARD POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Wood, Standard	30 to 35	$6.92	$0.23	**(I)**
Wood, Standard	40 to 55	8.10	0.27	**(I)**

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Acorn-Types						
HPS	100	9,500	43	*	$1.68	**(C)(R)**
HADCO Victorian, HPS	150	16,000	62	*	1.69	**(C)(R)**
	200	22,000	79	*	1.54	**(C)(R)**
	250	29,000	102	*	1.54	**(C)(R)**
HADCO Capitol Acorn, HPS	100	9,500	43	*	1.95	**(C)(R)**
	150	16,000	62	*	1.87	**(R)**
	200	22,000	79	*	1.98	**(R)**
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	*	1.63	**(R)**
	150	16,000	62	*	*	
						(D)
HADCO Techtra, HPS	150	16,000	62	*	*	**(C)**
	250	29,000	102	*	2.37	**(R)**
HADCO Westbrooke, HPS	70	6,300	30	*	1.77	**(C)(R)**
	100	9,500	43	*	1.76	**(C)(R)**
	150	16,000	62	*	1.95	**(R)**
	200	22,000	79	*	0.99	**(R)**
	250	29,000	102	*	1.74	**(C)(R)**

* Not offered. **(N)**

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Types						(D)
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	
Ornamental Acorn	55	2,800	21	*	*	
Ornamental Acorn Twin	55	5,600	42	*	*	
Composite, Twin	140	6,815	54	*	*	
	175	9,815	66	*	*	

* Not offered.
** Rates are based on current kWh energy charges.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$9.77	$0.32	(I)
	30	11.16	0.37	(I)
	35	12.87	0.42	(I)
Aluminum Davit	25	10.40	0.34	(I)
	30	11.67	0.38	(I)
	35	13.29	0.44	(I)
	40	17.04	0.56	(I)
Aluminum Double Davit	30	12.91	0.43	(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Fluted Ornamental	14	$9.14	$0.30	**(I)**
Aluminum, Smooth Techtra Ornamental	18	19.46	0.64	**(I)**
Aluminum, Fluted Ornamental	16	9.48	0.31	**(I)**
Aluminum, Double-Arm, Smooth Ornamental	25	15.40	0.51	**(I)**
Aluminum, Fluted Westbrooke	18	18.32	0.60	**(I)**
Aluminum, Non-Fluted Ornamental, Pendant	18	18.21	0.60	**(I)**
Fiberglass, Fluted Ornamental Black	14	12.05	0.40	**(I)**
Fiberglass, Anchor Base, Gray or Black	35	12.15	0.40	**(I)**
Fiberglass, Anchor Base (Color may vary)	25	10.89	0.36	**(I)**
	30	13.24	0.44	**(I)**

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Cobrahead, Metal Halide	150	10,000	60	*	*	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	*	$1.07	**(C)(R)**
	250	10,000	94	*	*	
	400	21,000	147	*	1.22	**(C)**
	1,000	55,000	374	*	*	**(C)**
Holophane Mongoose, HPS	150	16,000	62	*	1.67	**(R)**
	250	29,000	102	*	1.80	**(R)**
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	$6.49	*	
Mercury Vapor	175	7,000	66	*	1.15	**(C)(R)**

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Box, Anodized Aluminum						
Similar to GardCo Hub						
HPS	70	6,300	30	*	*	
						(D)
	150	16,000	62	*	*	
	250	29,000	102	*	*	
Metal Halide	250	20,500	99	*	$0.95	(R)
						(D)
Cobrahead, Metal Halide	175	12,000	71	*	*	
Flood, Metal Halide	400	40,000	156	*	*	(C)
Special Architectural Types						
Including Philips QL Induction						
Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	*	
	165	12,000	60	*	*	
HADCO Techtra, QL	165	12,000	60	*	1.07	(I)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	0.94	(R)
KIM Archetype, HPS	250	29,000	102	*	1.82	(R)
	400	50,000	163	*	2.17	(R)
Special Acorn-Type, HPS	70	6,300	30	*	1.47	(C)(R)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Early American Post-Top, HPS						
Black	70	6,300	30	*	$1.06	**(C)(R)**
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	*	1.10	**(C)(R)**
Flood, HPS						**(D)**
	200	22,000	79	*	1.16	**(C)(R)**
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Fluorescent	28	N/A	12	*	*	

* Not offered.

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Option A	Option B	
Aluminum Post	30	$5.23	*	**(I)**
Aluminum, Painted Ornamental	35	*	0.44	**(I)**
Aluminum, Regular	16	5.28	0.17	**(I)**
Concrete, Ornamental	35 or less	9.66	0.32	**(I)**
Fiberglass, Direct Bury with Shroud	18	7.78	0.26	**(I)**
Steel, Painted Regular **	25	9.66	0.32	**(I)**
Steel, Painted Regular **	30	11.01	*	**(I)(C)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	**(I)**
Steel, Unpainted 8-foot Mast Arm **	35	*	0.44	**(I)**
Wood, Laminated without Mast Arm	20	*	0.19	**(I)**
Wood, Curved Laminated	30	*	0.26	**(I)**
Wood, Painted Underground	35	6.85	0.23	**(I)**

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SCHEDULE 92
TRAFFIC SIGNALS
(NO NEW SERVICE)
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments where funds for payment of Electricity are provided through taxation or property assessment for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Transmission and Related Services Charge	0.543	¢ per kWh	**(I)**
Distribution Charge	2.064	¢ per kWh	**(I)**
Energy Charge	7.155	¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election (Continued)

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91/95 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires.

STREETLIGHT POLES SERVICE OPTIONS

See Schedule 91 for Streetlight poles service options.

MONTHLY RATE

In addition to the service rates for Option A and Option B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.511 ¢ per kWh	**(I)**
Distribution Charge	7.196 ¢ per kWh	
Energy Charge		
Cost of Service Option	6.697 ¢ per kWh	**(I)**

NON-COST OF SERVICE OPTION

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.315¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. **(R)**

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime [1]
	$132.00 per hour	$170.00 per hour

[1] Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Roadway LED	>20-25	3,000	8	$5.35	$0.39	(I)(R)
	>25-30	3,470	9	5.35	0.39	
	>30-35	2,530	11	5.62	0.39	
	>35-40	4,245	13	5.35	0.39	
	>40-45	5,020	15	5.52	0.39	
	>45-50	3,162	16	5.51	0.39	
	>50-55	3,757	18	5.79	0.39	
	>55-60	4,845	20	5.52	0.39	
	>60-65	4,700	21	5.52	0.39	
	>65-70	5,050	23	6.27	0.40	
	>70-75	7,640	25	6.30	0.40	
	>75-80	8,935	26	6.30	0.40	
	>80-85	9,582	28	6.30	0.40	
	>85-90	10,230	30	6.30	0.40	
	>90-95	9,928	32	6.30	0.40	
	>95-100	11,719	33	6.30	0.40	(I)
	>100-110	7,444	36	6.11	0.40	(R)
	>110-120	12,340	39	6.30	0.40	(I)
	>120-130	13,270	43	6.30	0.40	(I)
	>130-140	14,200	46	6.69	0.41	(R)
	>140-150	15,250	50	8.67	0.45	(I)
	>150-160	16,300	53	8.67	0.45	(I)
	>160-170	17,300	56	8.67	0.45	(I)
	>170-180	18,300	60	8.33	0.44	(I)
	>180-190	19,850	63	8.67	0.45	(I)
	>190-200	21,400	67	7.83	0.43	(R)(R)
	>200-210	27,033	70	7.90	0.43	(N)
	>210-220	28,535	74	8.69	0.45	
	>220-230	30,017	77	8.69	0.45	
	>230-240	30,800	81	8.69	0.45	
	>240-250	31,507	84	9.19	0.46	(N)

SCHEDULE 95 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn						
LED	>35-40	3,262	13	$13.72	$0.53	**(I)(R)**
	>40-45	3,500	15	13.72	0.53	
	>45-50	5,488	16	11.11	0.49	
	>50-55	4,000	18	13.72	0.53	
	>55-60	4,213	20	13.72	0.53	
	>60-65	4,273	21	13.72	0.53	
	>65-70	4,332	23	13.35	0.53	
	>70-75	4,897	25	13.72	0.53	**(I)(R)**
	>90-100	8,100	32	13.76	0.57	**(N)**
HADCO LED	70	5,120	24	17.31	0.60	**(I)(R)**
Pendant LED (Non-Flared)	36	3,369	12	14.32	0.54	**(R)(R)**
	53	5,079	18	15.46	0.56	**(R)**
	69	6,661	24	15.23	0.56	**(R)**
	85	8,153	29	15.79	0.57	**(R)(R)**
Pendant LED (Flared)	>35-40	3,369	13	13.74	0.53	**(R)(R)**
	>40-45	3,797	15	14.60	0.55	**(I)**
	>45-50	4,438	16	14.60	0.55	**(I)**
	>50-55	5,079	18	17.37	0.60	**(I)**
	>55-60	5,475	20	13.74	0.53	**(R)**
	>60-65	6,068	21	17.37	0.60	**(I)**
	>65-70	6,661	23	16.48	0.58	**(I)**
	>70-75	7,034	25	13.74	0.53	**(R)**
	>75-80	7,594	26	16.70	0.59	**(I)**
	>80-85	8,153	28	16.70	0.59	**(I)(R)**
Post-Top, American Revolution						
LED	>30-35	3,395	11	7.14	0.42	**(R)(R)**
	>45-50	4,409	16	7.14	0.42	**(R)(R)**
Flood LED	>80-85	10,530	28	7.41	0.42	**(I)(R)**
	>120-130	16,932	43	7.96	0.43	**(I)(R)**
	>180-190	23,797	63	9.17	0.45	**(I)(R)**
	>320-330	46,802	112	13.62	0.56	**(N)**
	>330-340	48,692	116	13.62	0.56	**(N)**
	>340-350	50,145	119	13.62	0.56	**(N)**
	>350-360	51,598	123	13.62	0.56	**(N)**
	>370-380	48,020	127	13.62	0.56	**(I)(R)**

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 general rate case, adjusted for a revenue sensitive cost factor of 1.0347. **(I)**

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.

SCHEDULE 126 (Continued)

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record both the Annual Power Cost Variance amounts and the RCE Power Cost Variance Amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. This account will accrue interest at the Commission-authorized rate for deferred accounts. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest calculated at the Commission-authorized rate. This amount will be added to the Adjustment

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0347 to account for franchise fees, uncollectibles, and OPUC fees. **(R)**

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount that is not the Exempted RCE Power Cost to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount that is not the Exempted RCE Power Cost to the extent that such refunding will not cause the Company's Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

DEFINITIONS

Actual Loads - Actual loads are total annual calendar retail loads adjusted to exclude loads of Customers to whom this adjustment schedule does not apply.

Actual NVPC - Incurred cost of power based on the definition for NVPC described here in. Actual NVPC will be increased by the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.

Actual Unit NVPC - The Actual Unit NVPC is calculated based on the following formula:

(Actual NVPC – 80% RCE costs) / (Actual Loads – 80% RCE Loads)

SCHEDULE 126 (Continued)

DEFINITIONS (Continued)

- Include Energy Charge revenues from Schedules 76R, 38, 83, 85, 89, 90, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485, 489, 490, 491, 492, 495 and 689 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.
- Include reciprocating engine lubrication oil expenses.
- Include actual State and Federal Production Tax Credits.

RCE Power Cost Mechanism – 80% of the RCE Power Cost that is exempt from the earnings test and deadbands.

RCE Load - Total retail load served by PGE during an RCE, adjusted to exclude loads of Customers to whom this adjustment schedule does not apply.

Reliability Contingency Event – An event qualifies as a Reliability Contingency Event (RCE) for cost recovery when at least 2 out of the 3 criteria are met:

1. The Day-ahead Mid-Columbia index prices exceed $150/MWh.
2. PGE is eligible to request or acquire resource adequacy (RA) assistance through a regional RA program in which it participates.
3. A neighboring Balancing Authority has publicly declared an event that indicates potential supply or actual supply constraints.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0347 to account for franchise fees, uncollectibles, and OPUC fees. **(R)**

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 126 (Continued)

TIME AND MANNER OF FILING (Continued)

Included in this filing will be the following information:

1. A transmittal letter that summarizes the proposed changes.
2. Revised Power Cost Variance Rates.
3. Work papers supporting the calculation of the revised PCV rates.

If the Company finds that the PCV Rates may over or under collect revenues in a particular year, the Company may recommend a modification of the Adjustment Rates to the Commission. The Company may also recommend that the Commission consider Adjustment Rates based on a collection or refund period different than one year based on the balance in the PCV Account.

POWER COST VARIANCE RATES

The PCV Rates will be determined on an equal cents per kWh basis. The PCV Rates are:

Schedule	Adjustment Rate	
7	0.000 ¢ per kWh	(R)
15/515	0.000 ¢ per kWh[(2)]	
32/535	0.000 ¢ per kWh[(2)]	
38/538	0.000 ¢ per kWh[(2)]	
47	0.000 ¢ per kWh	
49/549	0.000 ¢ per kWh[(2)]	
75/575		
Secondary	0.000 ¢ per kWh[(1)]	
Primary	0.000 ¢ per kWh[(1)]	
Subtransmission	0.000 ¢ per kWh[(1)]	
83/583	0.000 ¢ per kWh[(2)]	
85/585		
Secondary	0.000 ¢ per kWh[(2)]	
Primary	0.000 ¢ per kWh[(2)]	
89/589		
Secondary	0.000 ¢ per kWh[(2)]	
Primary	0.000 ¢ per kWh[(2)]	
Subtransmission	0.000 ¢ per kWh[(2)]	
90/590		
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
91/591	0.000 ¢ per kWh[(2)]	
92/592	0.000 ¢ per kWh[(2)]	
95/595	0.000 ¢ per kWh[(2)]	(R)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 126 (Concluded)

POWER COST VARIANCE RATES (Continued)

Schedule	Adjustment Rate	
485		
Secondary	0.000 ¢ per kWh[(2)]	(R)
Primary	0.000 ¢ per kWh[(2)]	
489		
Secondary	0.000 ¢ per kWh[(2)]	
Primary	0.000 ¢ per kWh[(2)]	
Subtransmission	0.000 ¢ per kWh[(2)]	
490		
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
491	0.000 ¢ per kWh	
492	0.000 ¢ per kWh	
495	0.000 ¢ per kWh	
689		
Secondary	0.000 ¢ per kWh[(2)]	
Primary	0.000 ¢ per kWh[(2)]	
Subtransmission	0.000 ¢ per kWh[(2)]	(R)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

TERM

Effective for service on and after January 17, 2007 and continuing until terminated by the Commission.

This schedule may only be terminated upon approval or order of the Commission. If this schedule is terminated for any reason, the Company will determine the remaining Adjustment Amount on a prorated basis consistent with the principles of this schedule. In such case, any balance in the PCV Account will be amortized to rates over a period to be determined by the Commission.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 85, 89, 90, 91 or 95 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592 and 595. This Schedule is not applicable to Customers served on Schedules 485, 489, 490, 491, 492 and 495.

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service in 2023, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2024:

Schedule		Annual Part A ¢ per kWh (1)	Annual Part B $ per kW of Peak Demand (3)	(C)
32		(2.649)		
38		(2.365)		
75	Secondary	(3.153) (2)		
	Primary	(3.118) (2)		
	Subtransmission	(3.390) (2)		
83		(5.620)	8.90	
85	Secondary	(5.727)	10.12	
	Primary	(5.609)	10.01	

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. **(N)**

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual Part A ¢ per kWh [(1)]	Annual Part B $ per kW of Peak Demand [(3)]	
				(C)
89	Secondary	(3.153)		
	Primary	(3.118)		
	Subtransmission	(3.390)		
90 30-250 MWa	Primary	(3.176)		
90 >250 MWa	Primary	(3.375)		
91		(2.454)		
95		(2.454)		
515		(2.431)		
532		(2.649)		
538		(2.365)		
549		(2.135)		
575	Secondary	(3.153) [(2)]		
	Primary	(3.118) [(2)]		
	Subtransmission	(3.390) [(2)]		
583		(5.620)	8.90	
585	Secondary	(5.727)	10.12	
	Primary	(5.609)	10.01	
589	Secondary	(3.153)		
	Primary	(3.118)		
	Subtransmission	(3.390)		
590 30-250 MWa	Primary	(3.176)		
590 >250 MWa	Primary	(3.375)		
591		(2.454)		
592		(3.397)		
595		(2.454)		

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. **(N)**

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term Transition Adjustment rate will be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. Indicative, non-binding estimates for the Annual Short-Term Transition Adjustment and Cost-of-Service Energy Prices will be posted by the Company by September 1 and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

SCHEDULE 128 (Concluded)

Second Quarter – April 1st Balance of Year Adjustment Rate (1)

Schedule		9-Month Part A ¢ per kWh (2)	9-Month Part B $ per kW of Peak Demand (4)	
				(C)
38		(5.092)		
75	Secondary	(4.539) (3)		
	Primary	(4.492) (3)		
	Subtransmission	(4.634) (3)		
83		(5.996)	4.68	
85	Secondary	(6.155)	5.17	
	Primary	(6.012)	5.15	
89	Secondary	(4.539)		
	Primary	(4.492)		
	Subtransmission	(4.634)		
90	Primary	(4.771)		
	Subtransmission	(4.771)		
91		(2.887)		
95		(2.887)		
538		(5.092)		
575	Secondary	(4.539) (3)		
	Primary	(4.492) (3)		
	Subtransmission	(4.634) (3)		
583		(5.996)	4.68	
585	Secondary	(6.155)	5.17	
	Primary	(6.012)	5.15	
589	Secondary	(4.539)		
	Primary	(4.492)		
	Subtransmission	(4.634)		
590	Primary	(4.771)		
	Subtransmission	(4.771)		
591		(2.887)		
592		(4.581)		
595		(2.887)		

(1) Applicable April 1, 2023 through December 31, 2023.
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.
(4) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. **(N)**

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

For Enrollment Period S (2020), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2021	3.167	3.137	2.801	2.749	2.770	2.704	2.666	
2022	2.475	2.474	2.216	2.197	2.247	2.144	2.119	
2023	2.475	2.474	2.216	2.197	2.247	2.144	2.119	
2024	2.619	2.599	2.328	2.307	2.355	2.238	2.179	
2025	3.216	3.190	2.919	2.891	2.934	2.815	2.693	**(I)**
After 2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period T (2021), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2022	0.851	0.845	0.590	0.602	0.606	0.564	0.669	
2023	0.851	0.845	0.590	0.602	0.606	0.564	0.669	
2024	0.995	0.970	0.702	0.712	0.714	0.658	0.729	
2025	1.592	1.561	1.293	1.296	1.293	1.235	1.243	**(I)**
2026	1.592	1.561	1.293	1.296	1.293	1.235	1.243	**(I)**
After 2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

For Enrollment Period U (2022), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2023	(1.985)	(1.799)	(0.766)	(0.758)	(0.798)	(0.825)	(0.769)	
2024	(1.845)	(1.677)	(0.629)	(0.651)	(0.693)	(0.734)	(0.706)	
2025	(1.248)	(1.086)	(0.038)	(0.067)	(0.114)	(0.157)	(0.192)	(I)
2026	(1.248)	(1.086)	(0.038)	(0.067)	(0.114)	(0.157)	(0.192)	(I)
2027	(1.248)	(1.086)	(0.038)	(0.067)	(0.114)	(0.157)	(0.192)	(I)
After 2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period U (2022), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ per kW of Peak Demand	(C)
2023	5.17	5.15	0.000	0.000	0.000	0.000	0.000	
2024	5.17	5.15	0.000	0.000	0.000	0.000	0.000	
2025	5.17	5.15	0.000	0.000	0.000	0.000	0.000	
2026	5.17	5.15	0.000	0.000	0.000	0.000	0.000	
2027	5.17	5.15	0.000	0.000	0.000	0.000	0.000	
After 2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out (Continued)

For Enrollment Period V (2023), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2024	(4.669)	(4.269)	(2.431)	(2.405)	(2.539)	(2.417)	(2.101)	
2025	(4.072)	(3.678)	(1.840)	(1.821)	(1.960)	(1.840)	(1.587)	(I)
2026	(4.072)	(3.678)	(1.840)	(1.821)	(1.960)	(1.840)	(1.587)	
2027	(4.072)	(3.678)	(1.840)	(1.821)	(1.960)	(1.840)	(1.587)	
2028	(4.072)	(3.678)	(1.840)	(1.821)	(1.960)	(1.840)	(1.587)	(I)
After 2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period V (2023), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ per kW of Peak Demand	(C)
2024	10.12	10.01	0.000	0.000	0.000	0.000	0.000	
2025	10.12	10.01	0.000	0.000	0.000	0.000	0.000	
2026	10.12	10.01	0.000	0.000	0.000	0.000	0.000	
2027	10.12	10.01	0.000	0.000	0.000	0.000	0.000	
2028	10.12	10.01	0.000	0.000	0.000	0.000	0.000	
After 2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out (Continued)

For Enrollment Period U (2022), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ per kW of Peak Demand	(C)
2023	5.17	5.15	0.000	0.000	0.000	0.000	0.000	
2024	5.17	5.15	0.000	0.000	0.000	0.000	0.000	
2025	5.17	5.15	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period V (2023), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ per kW of Peak Demand	(C)
2024	(5.205)	(5.134)	(2.870)	(2.840)	(2.905)	(3.116)	(2.398)	
2025	(4.724)	(4.696)	(2.351)	(2.327)	(2.336)	(2.615)	(1.978)	
2026	(4.532)	(4.508)	(2.147)	(2.125)	(2.094)	(2.442)	(2.094)	

For Enrollment Period V (2023), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ per kW of Peak Demand	(C)
2024	9.32	9.22	0.000	0.000	0.000	0.000	0.000	
2025	9.32	9.22	0.000	0.000	0.000	0.000	0.000	
2026	9.32	9.22	0.000	0.000	0.000	0.000	0.000	

SCHEDULE 131
OREGON CORPORATE ACTIVITY TAX RECOVERY

PURPOSE

To recover from Customers the Oregon Corporate Activity Tax (CAT) paid by the Company for "commercial activity" in accordance with House Bill 3427 and to establish an associated Automatic Adjustment Clause and balancing account.

APPLICABLE

To all bills for Electricity Service.

BALANCING ACCOUNT

A CAT Balancing Account will be maintained to accrue any difference between the Company's actual commercial activity tax liability and the amount collected from Customers under this Schedule. Any over or under-collection reflected in this account will be considered when the CAT Rate is established. The Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts.

CAT RECOVERY RATE DETERMINATION

The CAT Recovery Rate is determined by dividing the sum of forecast commercial activity tax liability plus or minus any amount in the Balancing Account divided by forecast Retail Revenue from Customers for each tax year or other applicable recovery period. Forecast Retail Revenue excludes Schedule 102, Schedule 108, Schedule 109, and Schedule 115, and all other separately stated taxes.

CAT RECOVERY RATE

The CAT Recovery Rate is:

0.000% of the total billed amount to the Customer excluding the RPA Credit (Schedule 102), Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes. **(I)**

SPECIAL CONDITION

1. Actual commercial activity tax liability is subject to audit. Any adjustments to the commercial activity tax liability will be included in the balancing account.

SCHEDULE 300
CHARGES AS DEFINED BY THE RULES AND REGULATIONS AND MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to list the charges referred to in the General Rules and Regulations.

AVAILABLE

In all territory served by the Company.

APPLICABLE

For all Customers utilizing the services of the Company as defined and described in the General Rules and Regulations.

INTEREST ACCRUED ON NON-RESIDENTIAL CUSTOMER DEPOSITS (See Rules E and K)

5.5% per annum.

BILLING RATES (Rules C, E, F, H, J, M and Sch 201)
Trouble call, cause in Customer-owned equipment

Scheduled Crew Hours [1]	No charge	
Other than Scheduled Crew Hours [1]	$270.00	
Returned Payment Charge	$ 25.00	
Special Meter Reading Charge (non-network)	$ 30.00	(I)
Meter Test Charge	$ 158.00	(I)
Late Payment Charge (monthly)	2.3% of delinquent balance	
Field Visit Charge [2]	$ 54.00	(I)
Bill History Information Service Charge (Not applicable when a billing dispute is filed with the Commission - see Rule F)	$ 32.00	
Portfolio Enrollment Charge	$ 5.00	
Customer Interval Data (12 months, formatted and analyzed)	Mutually agreed price	
Switching Fee	$20.00	
Unauthorized Connection of Service / Tamper Fee	$75.00	
Monthly Service Charge Sch 201 Qualifying Facility 10 MW or Less [3]	$151.00	

(1) Scheduled Crew Hours - The Company's Scheduled Crew Hours for the above listed services are from 7:00 a.m. to 3:30 p.m., Monday through Friday, except for Company-recognized holidays. The Customer will be informed of and agree to the charges before Company personnel are dispatched.
(2) See Rule H, Section 2 for applicable conditions.
(3) See Schedule 201 Monthly Service Charge. (Applicable only to new Standard Power Purchase Agreements after January 1, 2024).

SCHEDULE 300 (Continued)

PULSE OUTPUT METERING (Rule M)

Installation of Standard Meter Option (1 or 2 outputs) $ 575.00 **(I)**

Installation of Complex Meter Option (1 – 4 outputs) $1,525.00 **(I)**

NON-NETWORK RESIDENTIAL METER RATES (Rule M)

Installation of non-network meter (one time charge) $158.00 **(I)**

Non-network Meter Read $30.00 per month **(I)**

METER RELOCATION RATES (Rule M)

Single meter relocation	Estimated Actual Costs
Single meter relocation with Pole	Estimated Actual Costs

MISCELLANEOUS EQUIPMENT RENTAL (Rule C)

Rental of transformers, single-phase to three-phase inverters, capacitors, and other related equipment	1-2/3% per month of current replacement cost at time of installation

TRANSFORMERS (Rule I Section 3)

Submersible Transformers

For applications that require submersible transformers, which include but are not limited to network service areas and densely populated urban areas, the charge will be the calculated difference in cost between submersible and pad mount transformer installations including the costs of future maintenance.

SCHEDULE 300 (Concluded)

LINE EXTENSIONS (Rule I) Continued

Additional Services (Section 3)
(applies solely to Residential Subdivisions in Underground Service Areas)

Service Guarantee	$ 100.00	
Wasted Trip Charge	$ 203.00	(I)

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$1,225.00	(I)
Permanent Customer obtained		
Overhead Service	$725.00	(I)
Underground Service	$733.00	(I)
Existing service	$930.00	(I)

Enhanced Temporary Service

Fixed fee for initial 6-month period	$1,069.00	(I)
Fixed fee per 6-month renewal	$479.00	(I)

Temporary Area Lights — Estimated Actual Cost(1)

PGE TRAINING

Educational and Energy Efficiency (EE) training available to:

PGE Business Customer	No Charge(2)
Non-PGE Business Customer	Estimated Actual Cost(3)

(1) Based on install and removal labor for pole(s) and luminaire(s), including any construction costs (i.e., permitting, flagging, etc) and any facilities to energize luminaire(s). See Schedule 15 regarding the monthly energy and maintenance cost.
(2) Charges may be assessed for training courses registered through the states of Oregon and Washington for electrical licensees.
(3) Based on the cost associated with instructor, facility, food, and materials per attendee.

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per SP*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$880.00	$750.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.47	$3.43	(I)
Over 200 kW	$3.37	$3.33	
per kW of monthly On-Peak Demand	$1.73	$1.71	
System Usage Charge			
per kWh	0.065 ¢	0.065 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW more than once within the preceding 13 months and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per SP*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,190.00	$4,140.00	$5,860.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$2.04	$2.02	$2.00	(I)
Over 4,000 kW	$1.73	$1.71	$1.69	
per kW of monthly On-Peak Demand	$1.73	$1.71	$0.13	
System Usage Charge				
per kWh	0.030 ¢	0.029 ¢	0.029 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 490
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window*** enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to this and Schedules 485, 489, 490, 491, 492, and 495. Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per SP*:

	Delivery Voltage		
	Primary	Subtransmission	
Basic Charge	$18,500.00	$18,500.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$2.05	$2.05	(I)
Over 4,000 kW	$1.74	$1.74	
per kW of monthly on-peak Demand	$1.71	$0.13	
System Usage Charge			
per kWh	0.050 ¢	0.050¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 491 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 7.006 ¢ per kWh **(I)**

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's Service Points (SPs) under this schedule.

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$132.00 per hour	$170.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C		
Cobrahead Power Doors **	100	9,500	43	*	*	$3.01	(C) (D	(I)
	400	50,000	163	*	*	11.42	(C)	(I)
Cobrahead, Non-Power Door	70	6,300	30	8.26	3.26	2.10		(I)
	100	9,500	43	8.35	4.09	3.01		(I)
	150	16,000	62	*	5.43	4.34		(I)
	200	22,000	79	*	6.67	5.53	(C)	(I)
	250	29,000	102	*	8.28	7.15	(C)	(I)
	400	50,000	163	17.12	12.54	11.42		(I)
Flood	250	29,000	102	*	*	7.15	(C)	(I)
	400	50,000	163	*	*	11.42	(C)	(I)
Early American Post-Top	100	9,500	43	*	4.25	3.01		
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	*	3.25	2.10	(C)	(I)
	100	9,500	43	*	4.22	3.01		(I)
	150	16,000	62	*	5.60	4.34		(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black, Bronze or Gray	20	$5.69	$0.19	(I)
Fiberglass, Black or Bronze	30	9.26	0.31	(I)
Fiberglass, Gray	30	9.26	0.31	(I)
Fiberglass, Smooth, Black or Bronze	18	6.09	0.20	(I)
Fiberglass, Regular	18	5.13	0.17	(I)
Black, Bronze, or Gray	35	8.98	0.30	
Aluminum, Regular with Breakaway Base	25	16.56	0.55	(N)
	30	16.90	0.56	(N)
	35	18.28	0.60	(I)
Aluminum, Smooth, Black, Pendant	23	18.65	0.61	(I)
Wood, Standard	30 to 35	6.92	0.23	(I)
Wood, Standard	40 to 55	8.10	0.27	(I)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Acorn-Types							
HPS	100	9,500	43	*	$4.69	$3.01	(C)(I)
HADCO Victorian, HPS	150	16,000	62	*	6.03	4.34	(C)(I)
	200	22,000	79	*	7.07	5.53	(C)(I)
	250	29,000	102	*	8.69	7.15	(C)(I)
HADCO Capitol Acorn, HPS	100	9,500	43	*	4.96	3.01	(C)(I)
	150	16,000	62	*	6.21	4.34	(I)
	200	22,000	79	*	7.51	*	(I)
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	*	4.64	3.01	(C)(I)
	150	16,000	62	*	*	4.34	(I) (D)
HADCO Techtra, HPS	150	16,000	62	*	*	4.34	(C)(I)
	250	29,000	102	*	9.52	*	(I)
HADCO Westbrooke, HPS	70	6,300	30	*	3.87	*	(C)(I)
	100	9,500	43	*	4.77	3.01	(C)(I)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$6.29	*	**(R)**
	200	22,000	79	*	6.52	*	**(I)**
	250	29,000	102	*	8.89	*	**(I)**
Special Types							
							(D)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	$4.48	**(I)**
Ornamental Acorn	55	2,800	21	*	*	1.47	**(I)**
Ornamental Acorn Twin	55	5,600	42	*	*	2.94	**(I)**
Composite, Twin	140	6,815	54	*	*	3.78	**(I)**
	175	9,815	66	*	*	4.62	**(I)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$9.77	$0.32	**(I)**
	30	11.16	0.37	**(I)**
	35	12.87	0.42	**(I)**
Aluminum Davit	25	10.40	0.34	**(I)**
	30	11.67	0.38	**(I)**
	35	13.29	0.44	**(I)**
	40	17.04	0.56	**(I)**
Aluminum Double Davit	30	12.91	0.43	**(I)**
Aluminum, Fluted Ornamental	14	9.14	0.30	**(I)**

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, Smooth Techtra Ornamental	18	$19.46	$0.64	(I)
Aluminum, Fluted Ornamental	16	9.48	0.31	(I)
Aluminum, Double-Arm, Smooth Ornamental	25	15.40	0.51	(I)
Aluminum, Fluted Westbrooke	18	18.32	0.60	(I)
Aluminum, Non-Fluted Ornamental, Pendant	18	18.21	0.60	(I)
Fiberglass, Fluted Ornamental Black	14	12.05	0.40	(I)
Fiberglass, Anchor Base, Gray or Black	35	12.15	0.40	(I)
Fiberglass, Anchor Base (Color may vary)	25	10.89	0.36	(I)
	30	13.24	0.44	(I)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Cobrahead, Metal Halide	150	10,000	60	*	*	$4.20	(I)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.73	(I)
	175	7,000	66	*	$5.69	4.62	(C)(I)
	250	10,000	94	*	*	6.59	(I)
	400	21,000	147	*	*	10.30	(C)(I)
	1,000	55,000	374	$31.98	27.40	26.20	(I)
Holophane Mongoose,	150	16,000	62	*	6.01	*	(I)
HPS	250	29,000	102	*	8.95	*	(I)

* Not offered.

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$8.59	*	*	**(I)**
Mercury Vapor	175	7,000	66	*	$5.77	$4.62	**(C)(I)**
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	70	6,300	30	*	*	2.10	**(I)**
							(D)
	150	16,000	62	*	*	4.34	**(I)**
	250	29,000	102	*	*	7.15	**(I)**
Metal Halide	250	20,500	99	*	7.89	6.94	**(I)**
							(D)
Cobrahead, Metal Halide	175	12,000	71	*	*	4.97	**(I)**
Flood, Metal Halide	400	40,000	156	*	*	10.93	**(C)(I)**
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.28	4.34	**(I)**
KIM Archetype, HPS	250	29,000	102	*	8.97	7.15	**(I)**
	400	50,000	163	*	13.59	11.42	**(I)**

* Not offered

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	*	$3.57	*	**(C)(I)**
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$2.10	**(I)**
Mercury Vapor	175	7,000	66	*	*	4.62	**(I)**
Early American Post-Top, HPS							
Black	70	6,300	30	*	3.16	2.10	**(C)(I)**
Rectangle Type	200	22,000	79	*	*	5.53	**(I)**
Incandescent	92	1,000	31	*	*	2.17	**(I)**
	182	2,500	62	*	*	4.34	**(I)**
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	*	5.72	4.62	**(C)(I)**
							(D)
							(D)
Flood, HPS	200	22,000	79	*	6.69	5.53	**(C)(I)**
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	3.01	**(I)**
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.03	**(I)**
Compact Fluorescent	28	N/A	12	*	*	0.84	**(I)**

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$5.23	*	**(I)**
Aluminum, Painted Ornamental	35	*	$0.44	**(I)**
Aluminum, Regular	16	5.28	0.17	**(I)**
Concrete, Ornamental	35 or less	9.66	0.32	**(I)**
Fiberglass, Direct Bury with Shroud	18	7.78	0.26	**(I)**
Steel, Painted Regular **	25	9.66	0.32	**(I)**
Steel, Painted Regular **	30	11.01	*	**(I)(C)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	**(I)**
Steel, Unpainted 8-foot Mast Arm **	35	*	0.44	**(I)**
Wood, Laminated without Mast Arm	20	*	0.19	**(I)**
Wood, Curved Laminated	30	*	0.26	**(I)**
Wood, Painted Underground	35	6.85	0.23	**(I)**

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	*	$2.24	**(I)**
	165	12,000	60	*	*	4.20	**(I)**
	165	12,000	60	*	$5.27	4.20	**(C)(I)**

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 500 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Service Point (SP)* is:

Distribution Charge	1.861 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's SPs under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

SCHEDULE 495 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/491/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.006 ¢ per kWh	**(I)**

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's Service Points (SPs) under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [(1)]	Straight Time	Overtime
	$132.00 per hour	$170.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Roadway LED	>20-25	3,000	8	$5.91	$0.95	(I)(I)
	>25-30	3,470	9	5.98	1.02	
	>30-35	2,530	11	6.39	1.16	
	>35-40	4,245	13	6.26	1.30	
	>40-45	5,020	15	6.57	1.44	
	>45-50	3,162	16	6.63	1.51	
	>50-55	3,757	18	7.05	1.65	
	>55-60	4,845	20	6.92	1.79	
	>60-65	4,700	21	6.99	1.86	
	>65-70	5,050	23	7.88	2.01	
	>70-75	7,640	25	8.05	2.15	
	>75-80	8,935	26	8.12	2.22	
	>80-85	9,582	28	8.26	2.36	
	>85-90	10,230	30	8.40	2.50	
	>90-95	9,928	32	8.54	2.64	
	>95-100	11,719	33	8.61	2.71	
	>100-110	7,444	36	8.63	2.92	
	>110-120	12,340	39	9.03	3.13	
	>120-130	13,270	43	9.31	3.41	
	>130-140	14,200	46	9.91	3.63	
	>140-150	15,250	50	12.17	3.95	
	>150-160	16,300	53	12.38	4.16	
	>160-170	17,300	56	12.59	4.37	
	>170-180	18,300	60	12.53	4.64	
	>180-190	19,850	63	13.08	4.86	
	>190-200	21,400	67	12.52	5.12	(I)(I)
	>200-210	27,033	70	12.80	5.33	(N)
	>210-220	28,535	74	13.87	5.63	(N)
	>220-230	30,017	77	14.08	5.84	(N)
	>230-240	30,800	81	14.36	6.12	(N)
	>240-250	31,507	84	15.08	6.35	(N)

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn						
LED	>35-40	3,262	13	$14.63	$1.44	(I)(I)
	>40-45	3,500	15	14.77	1.58	
	>45-50	5,488	16	12.23	1.61	
	>50-55	4,000	18	14.98	1.79	
	>55-60	4,213	20	15.12	1.93	
	>60-65	4,273	21	15.19	2.00	
	>65-70	4,332	23	14.96	2.14	
	>70-75	4,897	25	15.47	2.28	(I)(I)
	>90-75	8,100	32	16.00	2.81	(N)
HADCO LED	70	5,120	24	18.99	2.28	(I)(I)
Pendant LED (Non-Flared)	36	3,369	12	15.16	1.38	(R)(I)
	53	5,079	18	16.72	1.82	(R)
	69	6,661	24	16.91	2.24	(R)
	85	8,153	29	17.82	2.60	(R)(I)
Pendant LED (Flared)	>35-40	3,369	13	14.65	1.44	(R)(I)
	>40-45	3,797	15	15.65	1.60	(I)
	>45-50	4,438	16	15.72	1.67	(I)
	>50-55	5,079	18	18.63	1.86	(I)
	>55-60	5,475	20	15.14	1.93	(R)
	>60-65	6,068	21	18.84	2.07	(I)
	>65-70	6,661	23	18.09	2.19	(I)
	>70-75	7,034	25	15.49	2.28	(R)
	>75-80	7,594	26	18.52	2.41	(I)
	>80-85	8,153	28	18.66	2.55	(I)(I)
Post-Top, American Revolution LED	>30-35	3,395	11	7.91	1.19	(R)(I)
	>45-50	4,409	16	8.26	1.54	(R)(I)
Flood LED	>80-85	10,530	28	9.37	2.38	(I)(I)
	>120-130	16,932	43	10.97	3.44	(I)(I)
	>180-190	23,797	63	13.58	4.86	(I)(I)
	>320-330	46,802	112	21.47	8.41	(N)
	>330-340	48,692	116	21.75	8.69	(N)
	>340-350	50,145	119	21.96	8.90	(N)
	>350-360	51,598	123	22.24	9.18	(N)
	>370-380	48,020	127	22.52	9.46	(N)

SCHEDULE 515
OUTDOOR AREA LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Nonresidential Customers purchasing Direct Access Service for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer or Electricity Service Supplier (ESS) notifies the Company of the burn-out.

MONTHLY RATE

The service rates below include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 7.006 ¢ per kWh (I)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$9.79[2]	(I)
	400	21,000	147	16.12[2]	
	1,000	55,000	374	31.90[2]	
HPS	70	6,300	30	8.18[2]	
	100	9,500	43	8.27	
	150	16,000	62	9.68	
	200	22,000	79	11.38	
	250	29,000	102	12.65	
	310	37,000	124	14.30[2]	
	400	50,000	163	17.04	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Flood , HPS	100	9,500	43	$8.15[2]	(I)
	200	22,000	79	12.83[2]	
	250	29,000	102	14.61	
	400	50,000	163	18.78	
Shoebox, HPS (bronze color, flat lens,	70	6,300	30	7.98	
or drop lens, multi-volt)	100	9,500	43	9.48	
	150	16,500	62	11.27	
Special Acorn Type, HPS	100	9,500	43	14.15	
HADCO Victorian, HPS	150	16,500	62	15.50	
Early American Post-Top, HPS, Black	100	9,500	43	9.79	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	11.88	
Cobrahead, Metal Halide	175	12,000	71	10.92	
Flood, Metal Halide	350	30,000	139	18.31	
Flood, Metal Halide	400	40,000	156	17.13	
Flood, HPS	750	105,000	285	30.72	
HADCO Independence, HPS	100	9,500	43	13.81	
HADCO Techtra, HPS	100	9,500	43	20.94	
	150	16,000	62	23.11	(I)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire	
Acorn					
LED	>35-40	3,262	13	$14.55	(I)
	>40-45	3,500	15	14.69	
	>45-50	5,488	16	12.15	
	>50-55	4,000	18	14.90	
	>55-60	4,213	20	15.04	
	>60-65	4,273	21	15.11	
	>65-70	4,332	23	14.88	
	>70-75	4,897	25	15.39	(I)
	>91-100	8,100	32	15.92	(N)
HADCO LED	70	5,120	24	18.91	(I)
Roadway LED	>20-25	3,000	8	5.83	(I)
	>25-30	3,470	9	5.90	
	>30-35	2,530	11	6.31	
	>35-40	4,245	13	6.18	
	>40-45	5,020	15	6.49	
	>45-50	3,162	16	6.55	
	>50-55	3,757	18	6.97	
	>55-60	4,845	20	6.84	
	>60-65	4,700	21	6.91	
	>65-70	5,050	23	7.80	
	>70-75	7,640	25	7.97	
	>75-80	8,935	26	8.04	
	>80-85	9,582	28	8.18	
	>85-90	10,230	30	8.32	
	>90-95	9,928	32	8.46	
	>95-100	11,719	33	8.53	
	>100-110	7,444	36	8.54	
	>110-120	12,340	39	8.95	
	>120-130	13,270	43	9.23	
	>130-140	14,200	46	9.83	
	>140-150	15,250	50	12.09	(I)
	>150-160	16,300	53	12.30	(I)(M)
	>160-170	17,300	56	12.51	(I)(M)
	>170-180	18,300	60	12.45	(I)(M)
	>180-190	19,850	63	13.00	(I)(M)
	>190-200	21,400	67	12.44	(I)(M)
	>200-210	27,033	70	12.73	(N)
	>210-220	28,535	74	13.79	(N)
	>220-230	30,017	77	14.00	(N)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[(1)] Per Luminaire	
Roadway LED (Cont)	>230-240	30,800	81	$14.28	**(N)**
	>240-250	31,507	84	15.00	**(N)**
Pendant LED (Non-Flare)	36	3,369	12	15.08	**(R)**
	53	5,079	18	16.64	**(R)**
	69	6,661	24	16.83	**(R)**
	85	8,153	29	17.74	**(R)**
Pendant LED (Flare)	>35-40	3,369	13	14.57	**(R)**
	>40-45	3,797	15	15.57	**(I)**
	>45-50	4,438	16	15.64	**(I)**
	>50-55	5,079	18	18.55	**(I)**
	>55-60	5,475	20	15.06	**(R)**
	>60-65	6,068	21	18.76	**(I)**
	>65-70	6,661	23	18.01	**(I)**
	>70-75	7,034	25	15.41	**(R)**
	>75-80	7,594	26	18.44	**(I)**
	>80-85	8,153	28	18.58	**(I)**
CREE XSP LED	>20-25	2,529	8	5.99	**(I)**
	>30-35	4,025	11	6.20	**(I)**
	>40-45	3,819	15	6.48	**(I)**
	>45-50	4,373	16	6.61	**(I)**
	>55-60	5,863	20	6.89	**(I)**
	>65-70	9,175	23	7.65	**(I)**
	>90-95	8,747	32	8.28	**(I)**
	130-140	18,700	46	10.77	**(I)**
Post-Top, American Revolution LED	>30-35	3,395	11	7.82	**(R)**
	>45-50	4,409	16	8.17	**(R)**
Flood LED	>80-85	10,530	28	9.29	**(I)**
	120-130	16,932	43	10.89	**(I)**
	180-190	23,797	63	13.50	**(I)**
	321-330	46,802	112	21.39	**(N)**
	331-340	48,692	116	21.67	**(N)**
	341-350	50,145	119	21.88	**(N)**
	351-360	51,598	123	22.16	**(N)**
	370-380	48,020	127	22.41	**(I)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)
Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$6.64	(I)
	40 to 55	7.82	
Wood, Painted Underground	35 or less	6.57[3]	
Wood, Curved laminated	30 or less	7.73[3]	
Aluminum, Regular	16	5.07	
	25	9.42	
	30	10.81	
	35	12.52	
Aluminum, Fluted Ornamental	14	8.93	
Aluminum, Fluted Ornamental	16	9.27	
Aluminum Davit	25	10.05	
	30	11.32	
	35	12.95	
	40	16.62	
Aluminum Double Davit	30	12.56	
Aluminum, Smooth Techtra Ornamental	18	19.11	
Fiberglass Fluted Ornamental; Black	14	11.77	
Fiberglass, Regular			
Black	20	5.48	
Gray or Bronze	30	8.91	
Black, Gray, or Bronze	35	8.70	
Fiberglass, Anchor Base, Gray or Black	35	11.87	
Fiberglass, Anchor Base (Color may vary)	25	10.55	
	30	12.89	
Fiberglass, Direct Bury with Shroud	18	7.43	
Aluminum, Regular with Breakaway Base	35	17.93	
Aluminum, Double-Arm, Smooth Ornamental	25	15.05	
Aluminum, Smooth, Black, Pendant	23	18.30	(I)
Aluminum, Regular with Breakaway Base	25	16.56	(N)
	30	16.90	(N)

(2) No pole charge for luminaires placed on existing Company-owned distribution poles.
(3) No new service.

INSTALLATION CHARGE
See Schedule 300 regarding the installation of conduit on wood poles.

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge		
Single Phase	$24.00	**(I)**
Three Phase	$33.00	**(I)**
Distribution Charge		
First 5,000 kWh	7.159 ¢ per kWh	**(I)**
Over 5,000 kWh	3.238 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 1) served at Secondary Demand Voltage whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW; or 2) who were receiving service on Schedule 38 as of December 31, 2015.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge			
Single Phase	$50.00		(I)
Three Phase	$60.00		(N)
Distribution Charge	9.286	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company’s investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge		
Summer Months**	\$60.00	**(I)**
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	13.158 ¢ per kWh	**(I)**
Over 50 kWh per kW of Demand	11.158 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply all or some portion of their load by self generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$4,190.00	$4,140.00	$5,860.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$2.04	$2.02	$2.00	(I)
Over 4,000 kW	$1.73	$1.71	$1.69	(I)
per kW of monthly Peak Demand**	$1.73	$1.71	$0.13	(I)(C)
Generation Contingency Reserves Charges***				
Spinning Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.030¢	0.029 ¢	0.029¢	(I)

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. (C)
*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge				
per kW of Daily ERP Demand during Peak hours per day**	$0.059	$0.058	$0.005	(C)
Transaction Fee				
per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. (C)

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

Basic Charge		
Single Phase Service	$50.00	**(I)**
Three Phase Service	$60.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$6.31	**(I)**
Over 30 kW	$6.21	**(I)**
per kW of monthly Peak Demand***	$1.73	**(I)(C)**
System Usage Charge		
per kWh	1.112 ¢	**(I)**

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. **(N)**

SCHEDULE 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$880.00	$750.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.47	$3.43	(I)
Over 200 kW	$3.37	$3.33	(I)
per kW of monthly Peak Demand***	$1.73	$1.71	(I)(C)
System Usage Charge			
per kWh	0.065 ¢	0.065 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. (N)

SCHEDULE 589
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW, and who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,190.00	$4,140.00	$5,860.00	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$2.04	$2.02	$2.00	**(I)**
Over 4,000 kW	$1.73	$1.71	$1.69	**(I)**
per kW of monthly Peak Demand***	$1.73	$1.71	$0.13	**(I)(C)**
System Usage Charge				
per kWh	0.030 ¢	0.029 ¢	0.029 ¢	**(I)**

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. **(N)**

SCHEDULE 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

	Delivery Voltage		
	Primary	Subtransmission	
Basic Charge	$18,500.00	$18,500.00	**(I)**
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$2.05	$2.05	**(I)**
Over 4,000 kW	$1.74	$1.74	**(I)**
per kW of monthly Peak Demand	$1.71	$0.13	**(I)(C)**
System Usage Charge			
per kWh	0.050 ¢	0.050 ¢	**(I)**

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company’s discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 7.006 ¢ per kWh (I)

Energy Charge Provided by Electricity Service Supplier

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company’s website, https://portlandgeneral.com

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$132.00 per hour	$170.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C		
Cobrahead Power Doors **	100	9,500	43	*	*	$3.01	(C) (D	(I)
	400	50,000	163	*	*	11.42	(C)	(I)
Cobrahead, Non-Power Door	70	6,300	30	8.26	3.26	2.10		(I)
	100	9,500	43	8.35	4.09	3.01		(I)
	150	16,000	62	*	5.43	4.34		(I)
	200	22,000	79	*	6.67	5.53	(C)	(I)
	250	29,000	102	*	8.28	7.15	(C)	(I)
	400	50,000	163	17.12	12.54	11.42		(I)
Flood	250	29,000	102	*	*	7.15	(C)	(I)
	400	50,000	163	*	*	11.42	(C)	(I)
Early American Post-Top	100	9,500	43	*	4.25	3.01		
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	*	3.25	2.10	(C)	(I)
	100	9,500	43	*	4.22	3.01		(I)
	150	16,000	62	*	5.60	4.34		(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 591 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black, Bronze or Gray	20	$5.69	$0.19	**(I)**
Fiberglass, Black or Bronze	30	9.26	0.31	**(I)**
Fiberglass, Gray	30	9.26	0.31	**(I)**
Fiberglass, Smooth, Black or Bronze	18	6.09	0.20	**(I)**
Fiberglass, Regular	18	5.13	0.17	**(I)**
Black, Bronze, or Gray	35	8.98	0.30	
Aluminum, Regular with Breakaway Base	25	16.56	0.55	**(N)**
	30	16.90	0.56	**(N)**
	35	18.28	0.60	**(I)**
Aluminum, Smooth, Black, Pendant	23	18.65	0.61	**(I)**
Wood, Standard	30 to 35	6.92	0.23	**(I)**
Wood, Standard	40 to 55	8.10	0.27	**(I)**

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Types							
HPS	100	9,500	43	*	$4.69	$3.01	**(C)(I)**
HADCO Victorian, HPS	150	16,000	62	*	6.03	4.34	**(C)(I)**
	200	22,000	79	*	7.07	5.53	**(C)(I)**
	250	29,000	102	*	8.69	7.15	**(C)(I)**
HADCO Capitol Acorn, HPS	100	9,500	43	*	4.96	3.01	**(C)(I)**
	150	16,000	62	*	6.21	4.34	**(I)**
	200	22,000	79	*	7.51	*	**(I)**
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	*	4.64	3.01	**(C)(I)**
	150	16,000	62	*	*	4.34	**(I)** **(D)**
HADCO Techtra, HPS	150	16,000	62	*	*	4.34	**(C)(I)**
	250	29,000	102	*	9.52	*	**(I)**
HADCO Westbrooke, HPS	70	6,300	30	*	3.87	*	**(C)(I)**
	100	9,500	43	*	4.77	3.01	**(C)(I)**

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$6.29	*	**(R)**
	200	22,000	79	*	6.52	*	**(I)**
	250	29,000	102	*	8.89	*	**(I)**
Special Types							
							(D)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	$4.48	**(I)**
Ornamental Acorn	55	2,800	21	*	*	1.47	**(I)**
Ornamental Acorn Twin	55	5,600	42	*	*	2.94	**(I)**
Composite, Twin	140	6,815	54	*	*	3.78	**(I)**
	175	9,815	66	*	*	4.62	**(I)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$9.77	$0.32	**(I)**
	30	11.16	0.37	**(I)**
	35	12.87	0.42	**(I)**
Aluminum Davit	25	10.40	0.34	**(I)**
	30	11.67	0.38	**(I)**
	35	13.29	0.44	**(I)**
	40	17.04	0.56	**(I)**
Aluminum Double Davit	30	12.91	0.43	**(I)**
Aluminum, Fluted Ornamental	14	9.14	0.30	**(I)**

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Smooth Techtra Ornamental	18	$19.46	$0.64	**(I)**
Aluminum, Fluted Ornamental	16	9.48	0.31	**(I)**
Aluminum, Double-Arm, Smooth Ornamental	25	15.40	0.51	**(I)**
Aluminum, Fluted Westbrooke	18	18.32	0.60	**(I)**
Aluminum, Non-Fluted Ornamental, Pendant	18	18.21	0.60	**(I)**
Fiberglass, Fluted Ornamental Black	14	12.05	0.40	**(I)**
Fiberglass, Anchor Base, Gray or Black	35	12.15	0.40	**(I)**
Fiberglass, Anchor Base (Color may vary)	25	10.89	0.36	**(I)**
	30	13.24	0.44	**(I)**

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Metal Halide	150	10,000	60	*	*	$4.20	**(I)**
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.73	**(I)**
	175	7,000	66	*	$5.69	4.62	**(C)(I)**
	250	10,000	94	*	*	6.59	**(I)**
	400	21,000	147	*	*	10.30	**(C)(I)**
	1,000	55,000	374	$31.98	27.40	26.20	**(I)**
Holophane Mongoose, HPS	150	16,000	62	*	6.01	*	**(I)**
	250	29,000	102	*	8.95	*	**(I)**

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$8.59	*	*	**(I)**
Mercury Vapor	175	7,000	66	*	$5.77	$4.62	**(C)(I)**
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	70	6,300	30	*	*	2.10	**(I)**
							(D)
	150	16,000	62	*	*	4.34	**(I)**
	250	29,000	102	*	*	7.15	**(I)**
Metal Halide	250	20,500	99	*	7.89	6.94	**(I)**
							(D)
Cobrahead, Metal Halide	175	12,000	71	*	*	4.97	**(I)**
Flood, Metal Halide	400	40,000	156	*	*	10.93	**(C)(I)**
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.28	4.34	**(I)**
KIM Archetype, HPS	250	29,000	102	*	8.97	7.15	**(I)**
	400	50,000	163	*	13.59	11.42	**(I)**

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	*	$3.57	*	**(C)(I)**
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$2.10	**(I)**
Mercury Vapor	175	7,000	66	*	*	4.62	**(I)**
Early American Post-Top, HPS							
Black	70	6,300	30	*	3.16	2.10	**(C)(I)**
Rectangle Type	200	22,000	79	*	*	5.53	**(I)**
Incandescent	92	1,000	31	*	*	2.17	**(I)**
	182	2,500	62	*	*	4.34	**(I)**
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	*	5.72	4.62	**(C)(I)**
							(D)
							(D)
Flood, HPS	200	22,000	79	*	6.69	5.53	**(C)(I)**
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	3.01	**(I)**
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.03	**(I)**
Compact Fluorescent	28	N/A	12	*	*	0.84	**(I)**

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B	
Aluminum Post	30	$5.23	*	**(I)**
Aluminum, Painted Ornamental	35	*	$0.44	**(I)**
Aluminum, Regular	16	5.28	0.17	**(I)**
Concrete, Ornamental	35 or less	9.66	0.32	**(I)**
Fiberglass, Direct Bury with Shroud	18	7.78	0.26	**(I)**
Steel, Painted Regular **	25	9.66	0.32	**(I)**
Steel, Painted Regular **	30	11.01	*	**(I)(C)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	**(I)**
Steel, Unpainted 8-foot Mast Arm **	35	*	0.44	**(I)**
Wood, Laminated without Mast Arm	20	*	0.19	**(I)**
Wood, Curved Laminated	30	*	0.26	**(I)**
Wood, Painted Underground	35	6.85	0.23	**(I)**

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	*	$2.24	**(I)**
	165	12,000	60	*	*	4.20	**(I)**
	165	12,000	60	*	$5.27	4.20	**(C)(I)**

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Service Point (SP)* is:

Distribution Charge	1.861 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 595 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election (Continued)

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91/95 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires.

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.006 ¢ per kWh	(I)
Energy Charge	Provided by Electricity Service Supplier	

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$132.00 per hour	$170.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Roadway LED	>20-25	3,000	8	$5.91	$0.95	(I)(I)
	>25-30	3,470	9	5.98	1.02	
	>30-35	2,530	11	6.39	1.16	
	>35-40	4,245	13	6.26	1.30	
	>40-45	5,020	15	6.57	1.44	
	>45-50	3,162	16	6.63	1.51	
	>50-55	3,757	18	7.05	1.65	
	>55-60	4,845	20	6.92	1.79	
	>60-65	4,700	21	6.99	1.86	
	>65-70	5,050	23	7.88	2.01	
	>70-75	7,640	25	8.05	2.15	
	>75-80	8,935	26	8.12	2.22	
	>80-85	9,582	28	8.26	2.36	
	>85-90	10,230	30	8.40	2.50	
	>90-95	9,928	32	8.54	2.64	
	>95-100	11,719	33	8.61	2.71	
	>100-110	7,444	36	8.63	2.92	
	>110-120	12,340	39	9.03	3.13	
	>120-130	13,270	43	9.31	3.41	
	>130-140	14,200	46	9.91	3.63	
	>140-150	15,250	50	12.17	3.95	
	>150-160	16,300	53	12.38	4.16	
	>160-170	17,300	56	12.59	4.37	
	>170-180	18,300	60	12.53	4.64	
	>180-190	19,850	63	13.08	4.86	
	>190-200	21,400	67	12.52	5.12	(I)(I)
	>200-210	27,033	70	12.80	5.33	(N)
	>210-220	28,535	74	13.87	5.63	(N)
	>220-230	30,017	77	14.08	5.84	(N)
	>230-240	30,800	81	14.36	6.12	(N)
	>240-250	31,507	84	15.08	6.35	(N)

SCHEDULE 595 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn						
LED	>35-40	3,262	13	$14.63	$1.44	**(I)(I)**
	>40-45	3,500	15	14.77	1.58	
	>45-50	5,488	16	12.23	1.61	
	>50-55	4,000	18	14.98	1.79	
	>55-60	4,213	20	15.12	1.93	
	>60-65	4,273	21	15.19	2.00	
	>65-70	4,332	23	14.96	2.14	
	>70-75	4,897	25	15.47	2.28	**(I)(I)**
	>90-75	8,100	32	16.00	2.81	**(N)**
HADCO LED	70	5,120	24	18.99	2.28	**(I)(I)**
Pendant LED (Non-Flared)	36	3,369	12	15.16	1.38	**(R)(I)**
	53	5,079	18	16.72	1.82	**(R)**
	69	6,661	24	16.91	2.24	**(R)**
	85	8,153	29	17.82	2.60	**(R)(I)**
Pendant LED (Flared)	>35-40	3,369	13	14.65	1.44	**(R)(I)**
	>40-45	3,797	15	15.65	1.60	**(I)**
	>45-50	4,438	16	15.72	1.67	**(I)**
	>50-55	5,079	18	18.63	1.86	**(I)**
	>55-60	5,475	20	15.14	1.93	**(R)**
	>60-65	6,068	21	18.84	2.07	**(I)**
	>65-70	6,661	23	18.09	2.19	**(I)**
	>70-75	7,034	25	15.49	2.28	**(R)**
	>75-80	7,594	26	18.52	2.41	**(I)**
	>80-85	8,153	28	18.66	2.55	**(I)(I)**
Post-Top, American Revolution LED	>30-35	3,395	11	7.91	1.19	**(R)(I)**
	>45-50	4,409	16	8.26	1.54	**(R)(I)**
Flood LED	>80-85	10,530	28	9.37	2.38	**(I)(I)**
	>120-130	16,932	43	10.97	3.44	**(I)(I)**
	>180-190	23,797	63	13.58	4.86	**(I)(I)**
	>320-330	46,802	112	21.47	8.41	**(N)**
	>330-340	48,692	116	21.75	8.69	**(N)**
	>340-350	50,145	119	21.96	8.90	**(N)**
	>350-360	51,598	123	22.24	9.18	**(N)**
	>370-380	48,020	127	22.52	9.46	

SCHEDULE 689 (Continued)

APPLICABLE (Continued)

Load served under Schedule 689 will not be counted under the Long Term Direct Access cap that applies to Schedules 485, 489, 490, 491, 492 and 495. The expected load of the Customer, defined as the “Contracted Load” in the opt out agreement between the Customer and the Company, will be the amount of load that is initially counted toward the New Load Direct Access cap for the first 60 months, unless a Customer is earlier de-enrolled under the terms of this Schedule 689 or the terms of the opt-out agreement.

The Contracted Load for each Customer will be counted toward the cap limit for up to the first 60 months of service. Following 60 months of service on Schedule 689, the Customer’s actual load factor (LF) will be applied to the contracted demand (MW) to calculate a Customer’s MWa to be captured and counted toward the New Large Load Program cap thereafter, and the total amount of load under the cap will be adjusted at such time of inquiry, in accordance with actual loads.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$4,190.00	$4,140.00	$5,860.00	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$2.04	$2.02	$2.00	**(I)**
Over 4,000 kW	$1.73	$1.71	$1.69	**(I)**
per kW of monthly Peak Demand	$1.73	$1.71	$0.13	**(I)(C)**
System Usage Charge				
per kWh	0.030 ¢	0.029 ¢	0.029 ¢	**(I)**
Administrative Fee	$0.00	$0.00	$0.00	

* See Schedule 100 for applicable adjustments.

** The Customer’s load, as reflected in the opt-out agreement executed between the Customer and PGE, may be higher than that reflected in a minimum load agreement for purposes of calculating the minimum monthly Facility Capacity and monthly Demand for the SP, for any Customer with dedicated substation capacity and/or redundant distribution facilities.

RULE C (Continued)

Short Term Emergency Curtailment (Continued)

The Company's Curtailment Plan and underlying operating procedures include, but are not limited to, steps for implementing rotating outages. During rotating outages the Company would discontinue Electricity Service to a specific number of circuits for approximately one-hour periods. If, after the first hour, system integrity were still in jeopardy, the circuits initially curtailed would have service restored while a second block of circuits would simultaneously have service discontinued. This cycle would continue until the Company determined that system emergency conditions no longer existed. Facilities deemed necessary to public health, safety and welfare are excluded from the rotating outage, as well as feeders serving Customers participating in the Schedule 88, Load Reduction Program.
During system emergencies, Customers having their own generation facilities or access to Electricity from non-utility power sources may choose to use energy from those other sources. The Company will not initiate its Curtailment Plan to avoid the purchase of high priced power. The Curtailment Plan is periodically updated and submitted to the Commission.

C. **Limitation of Liability**

The Company and its authorized contractors are not liable to Customers, ESSs or any other person or entity for any interruption, suspension, curtailment or fluctuation in Electricity Service, or for any loss or damage caused thereby, resulting from: **(C)**

1) Causes beyond the Company's reasonable control;
2) Repair, maintenance, improvement, renewal, or replacement of Facilities, or any discontinuance of service that the Company determines is necessary to permit repairs or changes to its Facilities or to eliminate the possibility of injuries to persons or damage to the Company's property or property of others. To the extent practical, such work will be done in a manner that will minimize inconvenience to the Customer, and whenever practical and applicable, the Customer will be given reasonable notice of such work, repairs, or changes;
3) An ESS's failure to abide by the terms of the ESS Service Agreement or the Tariff; Automatic or manual actions taken by the Company, including but not limited to Emergency Curtailments, that in its opinion, are necessary or prudent to protect the performance, integrity, reliability, or stability of the Company's electrical system or any electrical system with which it is interconnected; and
4) Actions taken by the Company to curtail Electricity use at times of anticipated resource deficiency in accordance with the applicable provisions of this Tariff.

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
JANUARY 2025

CATEGORY	RATE SCHEDULE	Forecast Dec 23E25 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT all supplementals except LIA &PPC	TOTAL ELECTRIC BILLS PROPOSED all supplementals except LIA & PPC	Change AMOUNT	Change PCT.	
Residential	7	829,611	7,889,185	$1,547,540,667	$1,658,393,845	$110,853,178	7.2%	
Employee Discount				($1,042,989)	($1,117,747)	($74,758)		
Subtotal				$1,546,497,678	$1,657,276,098	$110,778,420	7.2%	
Outdoor Area Lighting	15	0	13,091	$4,257,761	$4,544,766	$287,005	6.7%	
General Service <30 kW	32	96,384	1,550,351	$284,565,806	$311,448,589	$26,882,783	9.4%	
Opt. Time-of-Day G.S. >30 kW	38	353	27,036	$5,210,160	$5,789,879	$579,719	11.1%	
Irrig. & Drain. Pump. < 30 kW	47	2,764	20,520	$5,372,929	$5,970,809	$597,881	11.1%	
Irrig. & Drain. Pump. > 30 kW	49	1,377	59,354	$13,526,353	$15,031,437	$1,505,083	11.1%	
General Service 31-200 kW	83	11,811	2,867,544	$402,681,183	$441,038,001	$38,356,818	9.5%	
General Service 201-4,000 kW								
Secondary	85-S	1,260	2,074,490	$243,269,648	$260,908,338	$17,638,690	7.3%	
Primary	85-P	172	673,719	$68,450,606	$73,376,452	$4,925,846	7.2%	7.2%
Schedule 89 > 4 MW								
Primary	89-P	23	1,024,681	$92,564,008	$99,360,760	$6,796,752	7.3%	
Subtransmission	89-T/75-T	3	32,594	$3,423,300	$3,746,331	$323,032	9.4%	7.4%
Schedule 90	90-P	7	3,685,313	$302,725,316	$315,330,346	$12,605,030	4.2%	
Street & Highway Lighting	91/95	189	37,437	$13,667,932	$14,411,290	$743,357	5.4%	
Traffic Signals	92	16	2,724	$284,488	$299,395	$14,907	5.2%	
COS TOTALS		943,969	19,958,040	$2,986,497,167	$3,208,532,490	$222,035,323	7.4%	
Direct Access Service 201-4,000 kW								
Secondary	485-S	212	433,088	$13,057,680	$13,975,529	$917,849	7.0%	
Primary	485-P	50	304,716	$7,515,715	$8,274,595	$758,880	10.1%	8.1%
Direct Access Service > 4 MW								
Primary	489-P	17	1,096,147	$11,819,207	$12,708,759	$889,552	7.5%	
Subtransmission	489-T	3	249,687	$2,598,917	$2,920,496	$321,578	12.4%	8.4%
New Load Direct Access Service > 10MW								
Primary	689-P	4	256,336	$3,642,574	$3,202,857	($439,716)	-12.1%	
DIRECT ACCESS TOTALS		286	2,339,975	38,634,093	41,082,237	$2,448,144	6.3%	
COS AND DA CYCLE TOTALS		944,255	22,298,015	$3,025,131,259	$3,249,614,727	$224,483,468	**7.4%**	

TABLE 2
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
JUNE 2025

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast Dec 23E25)	MWH SALES	TOTAL ELECTRIC BILLS CURRENT all supplementals except LIA &PPC	TOTAL ELECTRIC BILLS PROPOSED all supplementals except LIA & PPC	Change AMOUNT	Change PCT.	
Residential	7	829,611	7,889,185	$1,547,540,667	$1,657,052,683	$109,512,016	7.1%	
Employee Discount				($1,042,989)	($1,116,788)	($73,799)		
Subtotal				$1,546,497,678	$1,655,935,895	$109,438,217	7.1%	
Outdoor Area Lighting	15	0	13,091	$4,257,761	$4,542,540	$284,779	6.7%	
General Service <30 kW	32	96,384	1,550,351	$284,565,806	$311,165,743	$26,599,938	9.3%	
Opt. Time-of-Day G.S. >30 kW	38	353	27,036	$5,210,160	$5,785,283	$575,123	11.0%	
Irrig. & Drain. Pump. < 30 kW	47	2,764	20,520	$5,372,929	$5,967,526	$594,598	11.1%	
Irrig. & Drain. Pump. > 30 kW	49	1,377	59,354	$13,526,353	$15,019,566	$1,493,213	11.0%	
General Service 31-200 kW	83	11,811	2,867,544	$402,681,183	$440,520,983	$37,839,801	9.4%	
General Service 201-4,000 kW								
Secondary	85-S	1,260	2,074,490	$243,269,648	$260,573,279	$17,303,631	7.1%	
Primary	85-P	172	673,719	$68,450,606	$73,153,188	$4,702,582	6.9%	7.1%
Schedule 89 > 4 MW								
Primary	89-P	23	1,024,681	$92,564,008	$99,154,162	$6,590,154	7.1%	
Subtransmission	89-T/75-T	3	32,594	$3,423,300	$3,739,963	$316,663	9.3%	7.2%
Schedule 90	90-P	7	3,685,313	$302,725,316	$314,943,641	$12,218,325	4.0%	
Street & Highway Lighting	91/95	189	37,437	$13,667,932	$14,405,674	$737,742	5.4%	
Traffic Signals	92	16	2,724	$284,488	$298,932	$14,444	5.1%	
COS TOTALS		943,969	19,958,040	$2,986,497,167	$3,205,206,376	$218,709,209	7.3%	
Direct Access Service 201-4,000 kW								
Secondary	485-S	212	433,088	$13,057,680	$13,982,677	$924,998	7.1%	
Primary	485-P	50	304,716	$7,515,715	$8,374,726	$859,012	11.4%	8.7%
Direct Access Service > 4 MW								
Primary	489-P	17	1,096,147	$11,819,207	$12,988,616	$1,169,409	9.9%	
Subtransmission	489-T	3	249,687	$2,598,917	$2,917,999	$319,082	12.3%	10.3%
New Load Direct Access Service > 10MW								
Primary	689-P	4	256,336	$3,642,574	$3,197,731	($444,843)	-12.2%	
DIRECT ACCESS TOTALS		286	2,339,975	38,634,093	41,461,749	$2,827,656	7.3%	
COS AND DA CYCLE TOTALS		944,255	22,298,015	$3,025,131,259	$3,246,668,125	$221,536,866	**7.3%**	

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
JANUARY 2025 TO JUNE 2025

				JANUARY 2025 IMPACTS			JUNE 2025 IMPACTS			JANUARY + JUNE IMPACTS		
CATEGORY	**RATE SCHEDULE**	CUSTOMERS	MWH SALES	all supplementals except LIA &PPC			AMOUNT	PCT.		all supplementals except LIA & PPC		
Residential	7	829,611	7,889,185	$110,853,178	7.2%		($1,341,162)	-0.1%		$109,512,016	7.1%	
Employee Discount				($74,758)						($73,799)		
Subtotal				$110,778,420	7.2%		($1,340,202)	-0.1%		$109,438,217	7.1%	
Outdoor Area Lighting	15	0	13,091	$287,005	6.7%		($2,225)	-0.1%		$284,779	6.7%	
General Service <30 kW	32	96,384	1,550,351	$26,882,783	9.4%		($282,846)	-0.1%		$26,599,938	9.3%	
Opt. Time-of-Day G.S. >30 kW	38	353	27,036	$579,719	11.1%		($4,596)	-0.1%		$575,123	11.0%	
Irrig. & Drain. Pump. < 30 kW	47	2,764	20,520	$597,881	11.1%		($3,283)	-0.1%		$594,598	11.1%	
Irrig. & Drain. Pump. > 30 kW	49	1,377	59,354	$1,505,083	11.1%		($11,871)	-0.1%		$1,493,213	11.0%	
General Service 31-200 kW	83	11,811	2,867,544	$38,356,818	9.5%		($517,018)	-0.1%		$37,839,801	9.4%	
General Service 201-4,000 kW												
Secondary	85-S	1,260	2,074,490	$17,638,690	7.3%		($335,059)	-0.1%		$17,303,631	7.1%	
Primary	85-P	172	673,719	$4,925,846	7.2%	7.2%	($223,264)	-0.3%	-0.2%	$4,702,582	6.9%	7.1%
Schedule 89 > 4 MW												
Primary	89-P	23	1,024,681	$6,796,752	7.3%		($206,598)	-0.2%		$6,590,154	7.1%	
Subtransmission	89-T/75-T	#REF!	#REF!	$323,032	9.4%	7.4%	($6,368)	-0.2%	-0.2%	$316,663	9.3%	7.2%
Schedule 90	90-P	#REF!	3,685,313	$12,605,030	4.2%		($386,705)	-0.1%		$12,218,325	4.0%	
Street & Highway Lighting	91/95	189	37,437	$743,357	5.4%		($5,616)	0.0%		$737,742	5.4%	
Traffic Signals	92	16	2,724	$14,907	5.2%		($463)	-0.2%		$14,444	5.1%	
COS TOTALS		#REF!	#REF!	$222,035,323	7.4%		($3,326,114)	-0.1%		$218,709,209	7.3%	
Direct Access Service 201-4,000 kW												
Secondary	485-S	212	433,088	$917,849	7.0%		$7,149	0.1%		$924,998	7.1%	
Primary	485-P	50	304,716	$758,880	10.1%	8.1%	$100,131	1.3%	-1.4%	$859,012	11.4%	8.7%
Direct Access Service > 4 MW												
Primary	489-P	17	1,096,147	$889,552	7.5%		$279,856	2.4%		$1,169,409	9.9%	
Subtransmission	489-T	3	249,687	$321,578	12.4%	8.4%	($2,497)	-0.1%	1.9%	$319,082	12.3%	10.3%
New Load Direct Access Service > 10MW												
Primary	689-P	4	256,336	($439,716)	-12.1%		($5,127)	-0.1%		($444,843)	-12.2%	
DIRECT ACCESS TOTALS		286	2,339,975	$2,448,144	6.3%		$379,512	1.0%		$2,827,656	7.3%	
							$0					
COS AND DA CYCLE TOTALS		#REF!	#REF!	$224,483,468	**7.4%**		($2,946,602)	-0.1%		$221,536,866	**7.3%**	

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills January 2025
Tariff Schedule 7

	Net Monthly Bill (Single-Family Home)			Net Monthly Bill (Multi-Family Home)		
kWh	**Current Prices**	**Proposed Prices**	**Percent Difference**	**Current Prices**	**Proposed Prices**	**Percent Difference**
50	$25.14	$27.78	10.5%	$22.14	$24.78	11.9%
100	$34.16	$37.38	9.4%	$31.16	$34.38	10.3%
200	$52.21	$56.60	8.4%	$49.21	$53.60	8.9%
250	$61.24	$66.21	8.1%	$58.24	$63.21	8.5%
300	$70.25	$75.81	7.9%	$67.25	$72.81	8.3%
400	$88.28	$95.00	7.6%	$85.28	$92.00	7.9%
500	$106.36	$114.25	7.4%	$103.36	$111.25	7.6%
600	$124.40	$133.47	7.3%	$121.40	$130.47	7.5%
700	$142.44	$152.66	7.2%	$139.44	$149.66	7.3%
795	$159.56	$170.91	7.1%	$156.56	$167.91	7.2%
800	$160.47	$171.87	7.1%	$157.47	$168.87	7.2%
850	$169.51	$181.50	7.1%	$166.51	$178.50	7.2%
900	$178.53	$191.09	7.0%	$175.53	$188.09	7.2%
1,000	$196.56	$210.30	7.0%	$193.56	$207.30	7.1%
1,100	$214.60	$229.50	6.9%	$211.60	$226.50	7.0%
1,200	$232.64	$248.72	6.9%	$229.64	$245.72	7.0%
1,300	$250.68	$267.93	6.9%	$247.68	$264.93	7.0%
1,400	$268.71	$287.12	6.9%	$265.71	$284.12	6.9%
1,500	$286.80	$306.38	6.8%	$283.80	$303.38	6.9%
1,600	$304.84	$325.58	6.8%	$301.84	$322.58	6.9%
1,700	$322.87	$344.77	6.8%	$319.87	$341.77	6.8%
1,800	$340.91	$363.98	6.8%	$337.91	$360.98	6.8%
2,000	$376.99	$402.41	6.7%	$373.99	$399.41	6.8%
2,300	$433.19	$462.12	6.7%	$430.19	$459.12	6.7%
2,750	$517.48	$551.67	6.6%	$514.48	$548.67	6.6%
3,000	$564.31	$601.41	6.6%	$561.31	$598.41	6.6%
3,500	$658.01	$700.95	6.5%	$655.01	$697.95	6.6%
4,000	$751.65	$800.42	6.5%	$748.65	$797.42	6.5%
4,500	$845.33	$899.95	6.5%	$842.33	$896.95	6.5%
5,000	$938.97	$999.42	6.4%	$935.97	$996.42	6.5%
7,500	$1,407.31	$1,496.96	6.4%	$1,404.31	$1,493.96	6.4%
10,000	$1,875.60	$1,994.44	6.3%	$1,872.60	$1,991.44	6.3%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills January 2025
Tariff Schedule 32, 1-phase Service

	Net Monthly Billing (without RPA credit)			Net Monthly Billing (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$108.28	$119.15	10.0%	$104.83	$115.70	10.4%
600	$125.45	$138.09	10.1%	$121.32	$133.96	10.4%
700	$142.66	$157.04	10.1%	$137.83	$152.22	10.4%
800	$159.87	$176.00	10.1%	$154.36	$170.49	10.5%
900	$177.06	$194.95	10.1%	$170.86	$188.74	10.5%
1,000	$194.23	$213.88	10.1%	$187.34	$206.99	10.5%
1,500	$280.21	$308.68	10.2%	$269.87	$298.33	10.5%
1,750	$323.20	$356.06	10.2%	$311.14	$344.00	10.6%
2,000	$366.17	$403.42	10.2%	$352.38	$389.63	10.6%
2,500	$452.15	$498.21	10.2%	$434.91	$480.97	10.6%
3,500	$624.07	$687.73	10.2%	$599.94	$663.61	10.6%
4,000	$710.02	$782.47	10.2%	$682.46	$754.91	10.6%
4,500	$796.01	$877.27	10.2%	$765.00	$846.25	10.6%
5,000	$881.96	$972.00	10.2%	$847.50	$937.54	10.6%
6,000	$1,026.68	$1,121.73	9.3%	$985.33	$1,080.38	9.6%
7,000	$1,171.40	$1,271.46	8.5%	$1,123.15	$1,223.21	8.9%
8,000	$1,316.12	$1,421.19	8.0%	$1,260.98	$1,366.06	8.3%
9,000	$1,460.84	$1,570.92	7.5%	$1,398.81	$1,508.89	7.9%
10,000	$1,605.56	$1,720.65	7.2%	$1,536.64	$1,651.73	7.5%
14,000	$2,184.46	$2,319.57	6.2%	$2,087.97	$2,223.09	6.5%
15,000	$2,329.17	$2,469.30	6.0%	$2,225.79	$2,365.92	6.3%
20,000	$3,052.78	$3,217.95	5.4%	$2,914.95	$3,080.12	5.7%
21,900	$3,327.76	$3,502.44	5.2%	$3,176.83	$3,351.51	5.5%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills January 2025
Tariff Schedule 32, 3-phase Service

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$117.41	$128.29	9.3%	$113.96	$124.84	9.5%
600	$134.58	$147.23	9.4%	$130.45	$143.09	9.7%
700	$151.77	$166.17	9.5%	$146.95	$161.35	9.8%
800	$168.98	$185.13	9.6%	$163.47	$179.62	9.9%
900	$186.18	$204.08	9.6%	$179.97	$197.88	9.9%
1,000	$203.35	$223.02	9.7%	$196.46	$216.13	10.0%
1,500	$289.34	$317.81	9.8%	$279.00	$307.47	10.2%
1,750	$332.33	$365.19	9.9%	$320.27	$353.13	10.3%
2,000	$375.29	$412.55	9.9%	$361.51	$398.77	10.3%
2,500	$461.27	$507.34	10.0%	$444.04	$490.11	10.4%
3,500	$633.20	$696.87	10.1%	$609.07	$672.74	10.5%
4,000	$719.15	$791.61	10.1%	$691.58	$764.04	10.5%
4,500	$805.13	$886.40	10.1%	$774.11	$855.38	10.5%
5,000	$891.08	$981.13	10.1%	$856.62	$946.67	10.5%
6,000	$1,035.80	$1,130.87	9.2%	$994.45	$1,089.52	9.6%
7,000	$1,180.52	$1,280.59	8.5%	$1,132.28	$1,232.35	8.8%
8,000	$1,325.24	$1,430.33	7.9%	$1,270.11	$1,375.19	8.3%
9,000	$1,469.96	$1,580.05	7.5%	$1,407.94	$1,518.03	7.8%
10,000	$1,614.69	$1,729.79	7.1%	$1,545.77	$1,660.87	7.4%
14,000	$2,193.57	$2,328.71	6.2%	$2,097.08	$2,232.22	6.4%
15,000	$2,338.29	$2,478.43	6.0%	$2,234.91	$2,375.05	6.3%
20,000	$3,061.91	$3,227.09	5.4%	$2,924.07	$3,089.25	5.6%

21,900	$3,336.88	$3,511.58	5.2%	$3,185.95	$3,360.65	5.5%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills January 2025
Tariff Schedule 47 Summer Period

		Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
10	50	$52.25	$53.76	2.9%	$51.90	$53.41	2.9%
10	100	$64.95	$67.96	4.6%	$64.26	$67.27	4.7%
10	500	$166.62	$181.44	8.9%	$163.17	$177.99	9.1%
10	1,000	$283.51	$313.10	10.4%	$276.62	$306.21	10.7%
10	2,000	$517.35	$576.46	11.4%	$503.56	$562.68	11.7%
10	5,000	$1,218.84	$1,366.53	12.1%	$1,184.38	$1,332.08	12.5%
20	100	$64.95	$67.96	4.6%	$64.26	$67.27	4.7%
20	200	$90.35	$96.32	6.6%	$88.97	$94.93	6.7%
20	500	$166.62	$181.44	8.9%	$163.17	$177.99	9.1%
20	1,000	$293.65	$323.25	10.1%	$286.76	$316.36	10.3%
20	2,000	$527.49	$586.61	11.2%	$513.70	$572.83	11.5%
20	5,000	$1,228.98	$1,376.68	12.0%	$1,194.52	$1,342.23	12.4%
20	8,000	$1,930.49	$2,166.77	12.2%	$1,875.35	$2,111.64	12.6%
30	150	$77.67	$82.14	5.8%	$76.63	$81.11	5.8%
30	500	$166.62	$181.44	8.9%	$163.17	$177.99	9.1%
30	1,000	$293.65	$323.25	10.1%	$286.76	$316.36	10.3%
30	3,000	$771.46	$860.12	11.5%	$750.78	$839.45	11.8%
30	5,000	$1,239.12	$1,386.83	11.9%	$1,204.66	$1,352.38	12.3%
30	8,000	$1,940.63	$2,176.92	12.2%	$1,885.49	$2,121.79	12.5%
30	10,000	$2,408.30	$2,703.64	12.3%	$2,339.38	$2,634.73	12.6%
30	15,000	$3,577.47	$4,020.44	12.4%	$3,474.09	$3,917.07	12.8%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 49 Summer Period January 2025

			Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
20%	35	5,110	$1,237.12	$1,371.61	10.9%	$1,201.90	$1,336.39	11.2%
40%	35	10,220	$2,388.08	$2,646.79	10.8%	$2,317.65	$2,576.36	11.2%
60%	35	15,330	$3,539.05	$3,921.99	10.8%	$3,433.40	$3,816.34	11.2%
80%	35	20,440	$4,690.02	$5,197.19	10.8%	$4,549.15	$5,056.32	11.1%
20%	50	7,300	$1,745.63	$1,933.36	10.8%	$1,695.32	$1,883.04	11.1%
40%	50	14,600	$3,389.83	$3,755.04	10.8%	$3,289.21	$3,654.42	11.1%
60%	50	21,900	$5,034.09	$5,576.74	10.8%	$4,883.16	$5,425.81	11.1%
80%	50	29,200	$6,678.30	$7,398.43	10.8%	$6,477.05	$7,197.19	11.1%
20%	70	10,220	$2,423.57	$2,682.31	10.7%	$2,353.14	$2,611.88	11.0%
40%	70	20,440	$4,725.51	$5,232.71	10.7%	$4,584.63	$5,091.84	11.1%
60%	70	30,660	$7,027.42	$7,783.06	10.8%	$6,816.11	$7,571.76	11.1%
80%	70	40,880	$9,329.37	$10,333.45	10.8%	$9,047.62	$10,051.71	11.1%
20%	100	14,600	$3,440.52	$3,805.79	10.6%	$3,339.90	$3,705.17	10.9%
40%	100	29,200	$6,728.99	$7,449.18	10.7%	$6,527.74	$7,247.94	11.0%
60%	100	43,800	$10,017.43	$11,092.55	10.7%	$9,715.57	$10,790.69	11.1%
80%	100	58,400	$13,305.91	$14,735.95	10.7%	$12,903.42	$14,333.46	11.1%
20%	200	29,200	$6,830.37	$7,550.68	10.5%	$6,629.12	$7,349.44	10.9%

40%	200	58,400	$13,407.29	$14,837.45	10.7%	$13,004.80	$14,434.96	11.0%
60%	200	87,600	$19,984.19	$22,124.22	10.7%	$19,380.47	$21,520.50	11.0%
80%	200	116,800	$26,561.11	$29,410.99	10.7%	$25,756.14	$28,606.02	11.1%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills January 2025
Tariff Schedule 38, 1-phase Service
Bill comparison assumes 51% on peak and 49% off peak energy consumption Current Prices
Bill comparison assumes 17% on peak 47% mid peak and 36% off peak energy consumption Proposed Prices

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
1,000	$226.63	$259.89	14.7%	$219.74	$253.00	15.1%
3,000	$608.92	$678.15	11.4%	$588.25	$657.47	11.8%
5,000	$991.21	$1,096.40	10.6%	$956.75	$1,061.94	11.0%
7,000	$1,373.49	$1,514.66	10.3%	$1,325.25	$1,466.42	10.7%
10,000	$1,946.93	$2,142.06	10.0%	$1,878.01	$2,073.14	10.4%
13,000	$2,520.36	$2,769.44	9.9%	$2,430.77	$2,679.85	10.2%
14,000	$2,711.51	$2,978.58	9.8%	$2,615.03	$2,882.10	10.2%
16,000	$3,093.80	$3,396.84	9.8%	$2,983.53	$3,286.57	10.2%
21,000	$4,049.52	$4,442.48	9.7%	$3,904.80	$4,297.75	10.1%
25,000	$4,814.10	$5,279.02	9.7%	$4,641.80	$5,106.72	10.0%
30,000	$5,769.82	$6,324.68	9.6%	$5,563.07	$6,117.93	10.0%
35,000	$6,725.55	$7,370.32	9.6%	$6,484.33	$7,129.11	9.9%
40,000	$7,681.26	$8,415.98	9.6%	$7,405.59	$8,140.30	9.9%
45,000	$8,636.98	$9,461.62	9.5%	$8,326.85	$9,151.49	9.9%
50,000	$9,592.71	$10,507.28	9.5%	$9,248.12	$10,162.69	9.9%
75,000	$14,371.33	$15,735.54	9.5%	$13,854.44	$15,218.65	9.8%
100,000	$19,149.95	$20,963.81	9.5%	$18,460.77	$20,274.62	9.8%
150,000	$28,707.18	$31,420.34	9.5%	$27,673.40	$30,386.56	9.8%
200,000	$38,264.41	$41,876.86	9.4%	$36,886.04	$40,498.49	9.8%
300,000	$57,378.88	$62,789.91	9.4%	$55,311.32	$60,722.36	9.8%
400,000	$76,493.34	$83,702.97	9.4%	$73,736.60	$80,946.23	9.8%
500,000	$95,587.80	$104,596.02	9.4%	$92,141.88	$101,150.09	9.8%
750,000	$137,235.07	$151,211.17	10.2%	$132,066.18	$146,042.28	10.6%
1,000,000	$182,801.59	$201,431.30	10.2%	$175,909.74	$194,539.45	10.6%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills January 2025
Tariff Schedule 38, 3-phase Service
Bill comparison assumes 51% on peak and 49% off peak energy consumption Current Prices
Bill comparison assumes 17% on peak 47% mid peak and 36% off peak energy consumption Proposed Prices

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
1,000	$226.63	$270.04	19.2%	$219.74	$263.15	19.8%
3,000	$608.92	$688.30	13.0%	$588.25	$667.62	13.5%
5,000	$991.21	$1,106.55	11.6%	$956.75	$1,072.09	12.1%
7,000	$1,373.49	$1,524.81	11.0%	$1,325.25	$1,476.57	11.4%
10,000	$1,946.93	$2,152.21	10.5%	$1,878.01	$2,083.29	10.9%
13,000	$2,520.36	$2,779.59	10.3%	$2,430.77	$2,690.00	10.7%
14,000	$2,711.51	$2,988.73	10.2%	$2,615.03	$2,892.25	10.6%
16,000	$3,093.80	$3,406.99	10.1%	$2,983.53	$3,296.72	10.5%
21,000	$4,049.52	$4,452.63	10.0%	$3,904.80	$4,307.90	10.3%
25,000	$4,814.10	$5,289.17	9.9%	$4,641.80	$5,116.87	10.2%
30,000	$5,769.82	$6,334.83	9.8%	$5,563.07	$6,128.08	10.2%
35,000	$6,725.55	$7,380.47	9.7%	$6,484.33	$7,139.26	10.1%
40,000	$7,681.26	$8,426.13	9.7%	$7,405.59	$8,150.45	10.1%
45,000	$8,636.98	$9,471.77	9.7%	$8,326.85	$9,161.64	10.0%
50,000	$9,592.71	$10,517.43	9.6%	$9,248.12	$10,172.84	10.0%
75,000	$14,371.33	$15,745.69	9.6%	$13,854.44	$15,228.80	9.9%
100,000	$19,149.95	$20,973.96	9.5%	$18,460.77	$20,284.77	9.9%
150,000	$28,707.18	$31,430.49	9.5%	$27,673.40	$30,396.71	9.8%
200,000	$38,264.41	$41,887.01	9.5%	$36,886.04	$40,508.64	9.8%
300,000	$57,378.88	$62,800.06	9.4%	$55,311.32	$60,732.51	9.8%
400,000	$76,493.34	$83,713.12	9.4%	$73,736.60	$80,956.38	9.8%
500,000	$95,587.80	$104,606.17	9.4%	$92,141.88	$101,160.24	9.8%
750,000	$137,235.07	$151,221.32	10.2%	$132,066.18	$146,052.43	10.6%
1,000,000	$182,801.59	$201,441.45	10.2%	$175,909.74	$194,549.60	10.6%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills January 2025
Tariff Schedule 83, Secondary, 3 phase service.
Bill comparison assumes 63% on peak and 37% off peak energy consumption Current Prices

Bill comparison assumes 19% on peak, 46% mid peak and 35% off peak energy consumption proposed prices

			Net Monthly Billing (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
30%	30	6,570	$1,118.28	$1,231.48	10.1%	$1,073.00	$1,186.20	10.5%
30%	50	10,950	$1,827.95	$2,009.83	9.9%	$1,752.49	$1,934.37	10.4%
30%	63	13,797	$2,289.26	$2,515.77	9.9%	$2,194.18	$2,420.68	10.3%
30%	75	16,425	$2,715.08	$2,982.78	9.9%	$2,601.88	$2,869.58	10.3%
30%	135	29,565	$4,844.16	$5,317.85	9.8%	$4,640.39	$5,114.08	10.2%
30%	175	38,325	$6,263.55	$6,874.58	9.8%	$5,999.41	$6,610.44	10.2%
30%	200	43,800	$7,150.65	$7,847.51	9.7%	$6,848.79	$7,545.65	10.2%
50%	30	10,950	$1,463.41	$1,602.61	9.5%	$1,387.94	$1,527.15	10.0%
50%	50	18,250	$2,403.21	$2,628.40	9.4%	$2,277.43	$2,502.62	9.9%
50%	63	21,250	$2,876.55	$3,147.30	9.4%	$2,730.10	$3,000.85	9.9%
50%	100	36,500	$4,752.71	$5,192.91	9.3%	$4,501.15	$4,941.35	9.8%
50%	135	49,275	$6,397.31	$6,987.99	9.2%	$6,057.71	$6,648.39	9.8%
50%	175	63,875	$8,276.90	$9,039.56	9.2%	$7,836.68	$8,599.34	9.7%
50%	200	73,000	$9,451.63	$10,321.78	9.2%	$8,948.52	$9,818.67	9.7%
70%	30	15,330	$1,808.55	$1,973.76	9.1%	$1,702.90	$1,868.10	9.7%
70%	50	25,550	$2,978.44	$3,246.97	9.0%	$2,802.36	$3,070.89	9.6%
70%	75	38,325	$4,440.80	$4,838.49	9.0%	$4,176.67	$4,574.35	9.5%
70%	100	51,100	$5,903.17	$6,429.98	8.9%	$5,550.99	$6,077.81	9.5%
70%	135	68,985	$7,950.48	$8,658.12	8.9%	$7,475.04	$8,182.68	9.5%
70%	175	89,425	$10,290.22	$11,204.52	8.9%	$9,673.92	$10,588.21	9.5%
70%	200	102,200	$11,752.59	$12,796.06	8.9%	$11,048.24	$12,091.71	9.4%
90%	30	19,710	$2,153.70	$2,344.90	8.9%	$2,017.87	$2,209.06	9.5%
90%	50	32,850	$3,553.67	$3,865.51	8.8%	$3,327.28	$3,639.12	9.4%
90%	75	49,275	$5,303.67	$5,766.34	8.7%	$4,964.07	$5,426.74	9.3%
90%	100	65,700	$7,053.66	$7,667.13	8.7%	$6,600.86	$7,214.34	9.3%
90%	135	88,695	$9,503.59	$10,328.22	8.7%	$8,892.31	$9,716.95	9.3%
90%	175	114,975	$12,303.56	$13,369.51	8.7%	$11,511.17	$12,577.12	9.3%
90%	200	131,400	$14,053.55	$15,270.31	8.7%	$13,147.96	$14,364.72	9.3%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills January 2025
Tariff Schedule 85, Secondary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption Currnet Prices
Bill Comparison assumes 19% on-peak, mid peak 42% and 39% off-peak energy consumption Proposed Prices

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$7,086.98	$7,683.67	8.4%
30%	300	65,700	$10,224.96	$11,068.77	8.3%
30%	500	109,500	$16,500.93	$17,838.92	8.1%
30%	700	153,300	$22,776.87	$24,609.07	8.0%
30%	800	175,200	$25,914.85	$27,994.16	8.0%
30%	900	197,100	$29,052.85	$31,379.27	8.0%
30%	1,000	219,000	$32,190.80	$34,764.32	8.0%
30%	1,500	328,500	$47,880.72	$51,689.74	8.0%
30%	2,000	438,000	$63,570.61	$68,615.14	7.9%
30%	4,000	876,000	$121,295.16	$131,832.33	8.7%
50%	200	73,000	$9,006.87	$9,693.43	7.6%
50%	300	109,500	$13,104.83	$14,083.42	7.5%
50%	500	182,500	$21,300.70	$22,863.38	7.3%
50%	700	255,500	$29,496.54	$31,643.30	7.3%
50%	800	292,000	$33,594.47	$36,033.25	7.3%
50%	900	328,500	$37,692.42	$40,423.24	7.2%
50%	1,000	365,000	$41,790.33	$44,813.19	7.2%
50%	1,500	547,500	$62,210.62	$66,693.66	7.2%
50%	2,000	730,000	$82,510.45	$88,453.70	7.2%
50%	4,000	1,460,000	$156,003.24	$168,704.89	8.1%
70%	200	102,200	$10,926.77	$11,703.22	7.1%
70%	300	153,300	$15,984.67	$17,098.07	7.0%
70%	500	255,500	$26,100.45	$27,887.80	6.8%
70%	700	357,700	$36,216.23	$38,677.52	6.8%
70%	800	408,800	$41,274.10	$44,072.35	6.8%
70%	900	459,900	$46,331.97	$49,467.21	6.8%
70%	1,000	511,000	$51,358.41	$54,830.63	6.8%
70%	1,500	766,500	$72,336.15	$77,974.99	7.8%
70%	2,000	1,022,000	$96,011.17	$103,495.47	7.8%
70%	4,000	2,044,000	$190,711.31	$205,577.44	7.8%
90%	200	131,400	$12,846.69	$13,713.00	6.7%
90%	300	197,100	$18,864.54	$20,112.77	6.6%
90%	500	328,500	$30,900.21	$32,912.24	6.5%
90%	700	459,900	$42,935.87	$45,711.71	6.5%
90%	800	525,600	$48,907.10	$52,064.85	6.5%
90%	900	591,300	$54,856.59	$58,396.26	6.5%
90%	1,000	657,000	$60,806.09	$64,727.68	6.4%
90%	1,500	985,500	$85,351.67	$91,802.19	7.6%
90%	2,000	1,314,000	$113,365.20	$121,931.74	7.6%
90%	4,000	2,628,000	$225,419.39	$242,450.01	7.6%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills January 2025
Tariff Schedule 85, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption
Bill Comparison assumes 19% on-peak, mid peak 42% and 39% off-peak energy consumption Proposed Prices

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$6,893.75	$7,458.45	8.2%
30%	300	65,700	$9,990.86	$10,796.88	8.1%
30%	500	109,500	$16,185.12	$17,473.82	8.0%
30%	700	153,300	$22,379.38	$24,150.70	7.9%
30%	800	175,200	$25,476.49	$27,489.14	7.9%
30%	900	197,100	$28,573.61	$30,827.59	7.9%
30%	1,000	219,000	$31,670.74	$34,166.03	7.9%
30%	1,500	328,500	$47,156.38	$50,858.31	7.9%
30%	2,000	438,000	$62,641.98	$67,550.51	7.8%
30%	4,000	876,000	$119,015.08	$129,300.68	8.6%
50%	200	73,000	$8,783.50	$9,434.46	7.4%
50%	300	109,500	$12,825.52	$13,760.95	7.3%
50%	500	182,500	$20,909.54	$22,413.87	7.2%
50%	700	255,500	$28,993.55	$31,066.78	7.2%
50%	800	292,000	$33,035.54	$35,393.21	7.1%

50%	900	328,500	$37,077.56	$39,719.70	7.1%
50%	1,000	365,000	$41,119.55	$44,046.12	7.1%
50%	1,500	547,500	$61,260.18	$65,609.03	7.1%
50%	2,000	730,000	$81,280.41	$87,051.49	7.1%
50%	4,000	1,460,000	$152,764.07	$165,141.83	8.1%
70%	200	102,200	$10,673.27	$11,410.48	6.9%
70%	300	153,300	$15,660.17	$16,724.96	6.8%
70%	500	255,500	$25,633.94	$27,353.91	6.7%
70%	700	357,700	$35,607.69	$37,982.80	6.7%
70%	800	408,800	$40,594.59	$43,297.27	6.7%
70%	900	459,900	$45,581.48	$48,611.74	6.6%
70%	1,000	511,000	$50,536.92	$53,894.76	6.6%
70%	1,500	766,500	$70,692.09	$76,169.62	7.7%
70%	2,000	1,022,000	$93,856.27	$101,132.27	7.8%
70%	4,000	2,044,000	$186,513.04	$200,982.98	7.8%
90%	200	131,400	$12,563.03	$13,386.50	6.6%
90%	300	197,100	$18,494.79	$19,688.98	6.5%
90%	500	328,500	$30,358.35	$32,293.96	6.4%
90%	700	459,900	$42,221.88	$44,898.87	6.3%
90%	800	525,600	$48,107.01	$51,154.74	6.3%
90%	900	591,300	$53,970.45	$57,388.89	6.3%
90%	1,000	657,000	$59,833.88	$63,623.01	6.3%
90%	1,500	985,500	$83,347.95	$89,610.05	7.5%
90%	2,000	1,314,000	$110,730.76	$119,052.84	7.5%
90%	4,000	2,628,000	$220,262.02	$236,824.13	7.5%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills January 2025
Tariff Schedule 89, Secondary.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption Current Prices
Bill Comparison assumes 18% on-peak, mid peak 40% and 42% off-peak energy consumption Proposed Prices

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$95,455.77	$105,181.08	10.2%
30%	7,500	1,642,500	$174,346.37	$191,954.52	10.1%
30%	10,000	2,190,000	$230,696.76	$253,935.52	10.1%
30%	15,000	3,285,000	$343,397.60	$377,897.56	10.0%
30%	20,000	4,380,000	$446,633.16	$492,382.75	10.2%
50%	4,000	1,460,000	$142,505.63	$154,404.57	8.3%
50%	7,500	2,737,500	$262,564.86	$284,248.57	8.3%
50%	10,000	3,650,000	$348,321.43	$376,994.24	8.2%
50%	15,000	5,475,000	$507,749.54	$550,385.83	8.4%
50%	20,000	7,300,000	$674,896.44	$731,505.62	8.4%
70%	4,000	2,044,000	$189,555.48	$203,628.05	7.4%
70%	7,500	3,832,500	$350,783.35	$376,542.59	7.3%
70%	10,000	5,110,000	$454,734.29	$488,827.47	7.5%
70%	15,000	7,665,000	$678,947.00	$729,727.98	7.5%
70%	20,000	10,220,000	$903,159.71	$970,628.48	7.5%
90%	4,000	2,628,000	$236,605.35	$252,851.54	6.9%
90%	7,500	4,927,500	$428,226.67	$458,048.30	7.0%
90%	10,000	6,570,000	$568,865.93	$608,388.90	6.9%
90%	15,000	9,855,000	$850,144.46	$909,070.12	6.9%
90%	20,000	13,140,000	$1,131,422.99	$1,209,751.35	6.9%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills January 2025
Tariff Schedule 89, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption
Bill Comparison assumes 18% on-peak, mid peak 40% and 42% off-peak energy consumption Proposed Prices

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$94,466.50	$104,054.80	10.1%
30%	7,500	1,642,500	$172,526.99	$189,887.15	10.1%
30%	10,000	2,190,000	$228,284.42	$251,195.94	10.0%
30%	15,000	3,285,000	$339,799.36	$373,813.56	10.0%
30%	20,000	4,380,000	$441,849.01	$486,954.33	10.2%
50%	4,000	1,460,000	$141,019.05	$152,750.73	8.3%
50%	7,500	2,737,500	$259,813.02	$281,192.04	8.2%
50%	10,000	3,650,000	$344,665.80	$372,935.77	8.2%
50%	15,000	5,475,000	$502,286.37	$544,323.49	8.4%
50%	20,000	7,300,000	$667,625.74	$723,439.41	8.4%
70%	4,000	2,044,000	$187,571.59	$201,446.66	7.4%
70%	7,500	3,832,500	$347,099.05	$372,496.89	7.3%
70%	10,000	5,110,000	$449,835.38	$483,450.10	7.5%
70%	15,000	7,665,000	$671,618.92	$721,687.30	7.5%
70%	20,000	10,220,000	$893,402.46	$959,924.50	7.4%
90%	4,000	2,628,000	$234,124.15	$250,142.59	6.8%
90%	7,500	4,927,500	$423,609.92	$453,013.43	6.9%
90%	10,000	6,570,000	$562,723.75	$601,692.64	6.9%
90%	15,000	9,855,000	$840,951.46	$899,051.11	6.9%
90%	20,000	13,140,000	$1,119,179.18	$1,196,409.58	6.9%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills January 2025
Tariff Schedule 89, Transmission

Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption
Bill Comparison assumes 18% on-peak, mid peak 40% and 42% off-peak energy consumption Proposed Prices

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$89,514.68	$98,336.94	9.9%
30%	5,000	1,095,000	$110,199.55	$120,994.55	9.8%
30%	10,000	2,190,000	$213,623.90	$234,282.59	9.7%
30%	20,000	4,380,000	$411,007.34	$451,381.83	9.8%
30%	40,000	8,760,000	$814,225.73	$894,042.16	9.8%
30%	50,000	10,950,000	$1,015,834.93	$1,115,372.32	9.8%
30%	70,000	15,330,000	$1,419,053.32	$1,558,032.64	9.8%
50%	4,000	1,460,000	$135,564.00	$146,523.10	8.1%
50%	5,000	1,825,000	$167,761.19	$181,227.25	8.0%
50%	10,000	3,650,000	$328,747.20	$354,747.98	7.9%
50%	20,000	7,300,000	$634,267.91	$685,318.04	8.0%
50%	40,000	14,600,000	$1,260,746.87	$1,361,914.59	8.0%
50%	50,000	18,250,000	$1,573,986.35	$1,700,212.86	8.0%
50%	70,000	25,550,000	$2,200,465.31	$2,376,809.40	8.0%
70%	4,000	2,044,000	$181,613.31	$194,709.26	7.2%
70%	5,000	2,555,000	$225,322.85	$241,459.93	7.2%
70%	10,000	5,110,000	$432,658.71	$463,987.88	7.2%
70%	20,000	10,220,000	$857,528.48	$919,254.26	7.2%
70%	40,000	20,440,000	$1,707,268.00	$1,829,787.02	7.2%
70%	50,000	25,550,000	$2,132,137.77	$2,285,053.40	7.2%
70%	70,000	35,770,000	$2,981,877.30	$3,195,586.16	7.2%
90%	4,000	2,628,000	$227,662.63	$242,895.41	6.7%
90%	5,000	3,285,000	$282,884.50	$301,692.63	6.6%
90%	10,000	6,570,000	$544,288.99	$580,955.99	6.7%
90%	20,000	13,140,000	$1,080,789.04	$1,153,190.47	6.7%
90%	40,000	26,280,000	$2,153,789.15	$2,297,659.46	6.7%
90%	50,000	32,850,000	$2,690,289.19	$2,869,893.95	6.7%
90%	70,000	45,990,000	$3,763,289.28	$4,014,362.92	6.7%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills January 2025
Tariff Schedule 90 (30 MWa), Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
80%	3,000	1,752,000	$165,303.72	$182,720.24	10.5%
80%	13,000	7,592,000	$653,444.84	$707,526.66	8.3%
80%	23,000	13,432,000	$1,144,449.56	$1,235,200.17	7.9%
80%	33,000	19,272,000	$1,635,454.27	$1,762,873.68	7.8%
80%	43,000	25,112,000	$2,126,458.98	$2,290,547.19	7.7%
80%	53,000	30,952,000	$2,617,463.68	$2,818,220.69	7.7%
80%	63,000	36,792,000	$3,108,468.40	$3,345,894.20	7.6%
90%	3,000	1,971,000	$182,312.94	$200,672.72	10.1%
90%	13,000	8,541,000	$724,880.98	$783,047.48	8.0%
90%	23,000	15,111,000	$1,270,836.57	$1,368,813.93	7.7%
90%	33,000	21,681,000	$1,816,792.15	$1,954,580.38	7.6%
90%	43,000	28,251,000	$2,362,747.74	$2,540,346.82	7.5%
90%	53,000	34,821,000	$2,908,703.32	$3,126,113.27	7.5%
90%	63,000	41,391,000	$3,454,658.90	$3,711,879.72	7.4%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills January 2025
Tariff Schedule 90 (250 MWa or higher), Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
80%	250,000	146,000,000	$12,032,955.57	$12,485,775.92	3.8%
80%	260,000	151,840,000	$12,513,626.08	$12,984,344.91	3.8%
80%	270,000	157,680,000	$12,994,296.57	$13,482,913.91	3.8%
80%	280,000	163,520,000	$13,474,967.09	$13,981,482.90	3.8%
80%	290,000	169,360,000	$13,955,637.58	$14,480,051.90	3.8%
80%	300,000	175,200,000	$14,436,308.08	$14,978,620.88	3.8%
80%	310,000	181,040,000	$14,916,978.57	$15,477,189.87	3.8%
90%	250,000	164,250,000	$13,374,433.02	$13,847,147.77	3.5%
90%	260,000	170,820,000	$13,908,762.62	$14,400,171.64	3.5%
90%	270,000	177,390,000	$14,443,092.22	$14,953,195.51	3.5%
90%	280,000	183,960,000	$14,977,421.82	$15,506,219.37	3.5%
90%	290,000	190,530,000	$15,511,751.42	$16,059,243.24	3.5%
90%	300,000	197,100,000	$16,046,081.02	$16,612,267.11	3.5%
90%	310,000	203,670,000	$16,580,410.61	$17,165,290.97	3.5%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills June 2025
Tariff Schedule 7

	Net Monthly Bill (Single-Family Home)			Net Monthly Bill (Multi-Family Home)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
50	$25.14	$27.77	10.5%	$22.14	$24.77	11.9%
100	$34.16	$37.36	9.4%	$31.16	$34.36	10.3%
200	$52.21	$56.57	8.4%	$49.21	$53.57	8.9%
250	$61.24	$66.16	8.0%	$58.24	$63.16	8.5%
300	$70.25	$75.75	7.8%	$67.25	$72.75	8.2%
400	$88.28	$94.93	7.5%	$85.28	$91.93	7.8%
500	$106.36	$114.18	7.3%	$103.36	$111.18	7.6%
600	$124.40	$133.36	7.2%	$121.40	$130.36	7.4%
700	$142.44	$152.55	7.1%	$139.44	$149.55	7.2%
795	$159.56	$170.77	7.0%	$156.56	$167.77	7.2%
800	$160.47	$171.73	7.0%	$157.47	$168.73	7.2%
850	$169.51	$181.34	7.0%	$166.51	$178.34	7.1%
900	$178.53	$190.93	6.9%	$175.53	$187.93	7.1%
1,000	$196.56	$210.12	6.9%	$193.56	$207.12	7.0%
1,100	$214.60	$229.31	6.9%	$211.60	$226.31	7.0%
1,200	$232.64	$248.52	6.8%	$229.64	$245.52	6.9%
1,300	$250.68	$267.70	6.8%	$247.68	$264.70	6.9%
1,400	$268.71	$286.88	6.8%	$265.71	$283.88	6.8%
1,500	$286.80	$306.13	6.7%	$283.80	$303.13	6.8%
1,600	$304.84	$325.31	6.7%	$301.84	$322.31	6.8%
1,700	$322.87	$344.49	6.7%	$319.87	$341.49	6.8%
1,800	$340.91	$363.67	6.7%	$337.91	$360.67	6.7%
2,000	$376.99	$402.06	6.7%	$373.99	$399.06	6.7%
2,300	$433.19	$461.71	6.6%	$430.19	$458.71	6.6%
2,750	$517.48	$551.18	6.5%	$514.48	$548.18	6.6%
3,000	$564.31	$600.90	6.5%	$561.31	$597.90	6.5%
3,500	$658.01	$700.36	6.4%	$655.01	$697.36	6.5%
4,000	$751.65	$799.73	6.4%	$748.65	$796.73	6.4%
4,500	$845.33	$899.19	6.4%	$842.33	$896.19	6.4%
5,000	$938.97	$998.56	6.3%	$935.97	$995.56	6.4%
7,500	$1,407.31	$1,495.68	6.3%	$1,404.31	$1,492.68	6.3%
10,000	$1,875.60	$1,992.72	6.2%	$1,872.60	$1,989.72	6.3%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills June 2025
Tariff Schedule 32, 1-phase Service

	Net Monthly Billing (without RPA credit)			Net Monthly Billing (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$108.28	$119.06	10.0%	$104.83	$115.61	10.3%
600	$125.45	$137.98	10.0%	$121.32	$133.85	10.3%
700	$142.66	$156.91	10.0%	$137.83	$152.09	10.4%
800	$159.87	$175.83	10.0%	$154.36	$170.32	10.3%
900	$177.06	$194.77	10.0%	$170.86	$188.57	10.4%
1,000	$194.23	$213.70	10.0%	$187.34	$206.81	10.4%
1,500	$280.21	$308.40	10.1%	$269.87	$298.06	10.4%
1,750	$323.20	$355.71	10.1%	$311.14	$343.65	10.4%
2,000	$366.17	$403.04	10.1%	$352.38	$389.26	10.5%
2,500	$452.15	$497.74	10.1%	$434.91	$480.51	10.5%
3,500	$624.07	$687.08	10.1%	$599.94	$662.96	10.5%
4,000	$710.02	$781.72	10.1%	$682.46	$754.15	10.5%
4,500	$796.01	$876.42	10.1%	$765.00	$845.40	10.5%
5,000	$881.96	$971.06	10.1%	$847.50	$936.60	10.5%
6,000	$1,026.68	$1,120.58	9.1%	$985.33	$1,079.23	9.5%
7,000	$1,171.40	$1,270.11	8.4%	$1,123.15	$1,221.86	8.8%
8,000	$1,316.12	$1,419.63	7.9%	$1,260.98	$1,364.49	8.2%
9,000	$1,460.84	$1,569.15	7.4%	$1,398.81	$1,507.12	7.7%
10,000	$1,605.56	$1,718.67	7.0%	$1,536.64	$1,649.75	7.4%
14,000	$2,184.46	$2,316.76	6.1%	$2,087.97	$2,220.28	6.3%
15,000	$2,329.17	$2,466.28	5.9%	$2,225.79	$2,362.91	6.2%
20,000	$3,052.78	$3,213.89	5.3%	$2,914.95	$3,076.06	5.5%
21,900	$3,327.76	$3,497.99	5.1%	$3,176.83	$3,347.06	5.4%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills June 2025
Tariff Schedule 32, 3-phase Service

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$117.41	$128.20	9.2%	$113.96	$124.74	9.5%
600	$134.58	$147.11	9.3%	$130.45	$142.98	9.6%
700	$151.77	$166.04	9.4%	$146.95	$161.22	9.7%
800	$168.98	$184.97	9.5%	$163.47	$179.46	9.8%
900	$186.18	$203.91	9.5%	$179.97	$197.71	9.9%
1,000	$203.35	$222.84	9.6%	$196.46	$215.94	9.9%
1,500	$289.34	$317.54	9.7%	$279.00	$307.19	10.1%
1,750	$332.33	$364.85	9.8%	$320.27	$352.79	10.2%
2,000	$375.29	$412.18	9.8%	$361.51	$398.39	10.2%
2,500	$461.27	$506.88	9.9%	$444.04	$489.64	10.3%
3,500	$633.20	$696.22	10.0%	$609.07	$672.09	10.3%
4,000	$719.15	$790.86	10.0%	$691.58	$763.29	10.4%
4,500	$805.13	$885.56	10.0%	$774.11	$854.54	10.4%
5,000	$891.08	$980.20	10.0%	$856.62	$945.74	10.4%
6,000	$1,035.80	$1,129.72	9.1%	$994.45	$1,088.37	9.4%
7,000	$1,180.52	$1,279.24	8.4%	$1,132.28	$1,231.00	8.7%
8,000	$1,325.24	$1,428.76	7.8%	$1,270.11	$1,373.63	8.2%
9,000	$1,469.96	$1,578.29	7.4%	$1,407.94	$1,516.26	7.7%
10,000	$1,614.69	$1,727.81	7.0%	$1,545.77	$1,658.89	7.3%
14,000	$2,193.57	$2,325.90	6.0%	$2,097.08	$2,229.41	6.3%
15,000	$2,338.29	$2,475.42	5.9%	$2,234.91	$2,372.04	6.1%
20,000	$3,061.91	$3,223.03	5.3%	$2,924.07	$3,085.19	5.5%

21,900	$3,336.88	$3,507.12	5.1%	$3,185.95	$3,356.19	5.3%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills June 2025
Tariff Schedule 47 Summer Period

		Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
10	50	$52.25	$53.76	2.9%	$51.90	$53.41	2.9%
10	100	$64.95	$67.94	4.6%	$64.26	$67.25	4.6%
10	500	$166.62	$181.36	8.8%	$163.17	$177.91	9.0%
10	1,000	$283.51	$312.93	10.4%	$276.62	$306.04	10.6%
10	2,000	$517.35	$576.13	11.4%	$503.56	$562.35	11.7%
10	5,000	$1,218.84	$1,365.73	12.1%	$1,184.38	$1,331.27	12.4%
20	100	$64.95	$67.94	4.6%	$64.26	$67.25	4.6%
20	200	$90.35	$96.28	6.6%	$88.97	$94.90	6.7%
20	500	$166.62	$181.36	8.8%	$163.17	$177.91	9.0%
20	1,000	$293.65	$323.08	10.0%	$286.76	$316.19	10.3%
20	2,000	$527.49	$586.28	11.1%	$513.70	$572.50	11.4%
20	5,000	$1,228.98	$1,375.88	12.0%	$1,194.52	$1,341.42	12.3%
20	8,000	$1,930.49	$2,165.48	12.2%	$1,875.35	$2,110.35	12.5%
30	150	$77.67	$82.11	5.7%	$76.63	$81.08	5.8%
30	500	$166.62	$181.36	8.8%	$163.17	$177.91	9.0%
30	1,000	$293.65	$323.08	10.0%	$286.76	$316.19	10.3%
30	3,000	$771.46	$859.63	11.4%	$750.78	$838.96	11.7%
30	5,000	$1,239.12	$1,386.03	11.9%	$1,204.66	$1,351.57	12.2%
30	8,000	$1,940.63	$2,175.63	12.1%	$1,885.49	$2,120.50	12.5%
30	10,000	$2,408.30	$2,702.03	12.2%	$2,339.38	$2,633.11	12.6%
30	15,000	$3,577.47	$4,018.03	12.3%	$3,474.09	$3,914.65	12.7%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills June 2025
Tariff Schedule 49 Summer Period

			Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
20%	35	5,110	$1,237.12	$1,370.54	10.8%	$1,201.90	$1,335.32	11.1%
40%	35	10,220	$2,388.08	$2,644.66	10.7%	$2,317.65	$2,574.23	11.1%
60%	35	15,330	$3,539.05	$3,918.80	10.7%	$3,433.40	$3,813.15	11.1%
80%	35	20,440	$4,690.02	$5,192.94	10.7%	$4,549.15	$5,052.07	11.1%
20%	50	7,300	$1,745.63	$1,931.86	10.7%	$1,695.32	$1,881.54	11.0%
40%	50	14,600	$3,389.83	$3,752.02	10.7%	$3,289.21	$3,651.40	11.0%
60%	50	21,900	$5,034.09	$5,572.21	10.7%	$4,883.16	$5,421.28	11.0%
80%	50	29,200	$6,678.30	$7,392.38	10.7%	$6,477.05	$7,191.14	11.0%
20%	70	10,220	$2,423.57	$2,680.19	10.6%	$2,353.14	$2,609.76	10.9%
40%	70	20,440	$4,725.51	$5,228.47	10.6%	$4,584.63	$5,087.60	11.0%
60%	70	30,660	$7,027.42	$7,776.71	10.7%	$6,816.11	$7,565.41	11.0%
80%	70	40,880	$9,329.37	$10,324.99	10.7%	$9,047.62	$10,043.25	11.0%
20%	100	14,600	$3,440.52	$3,802.76	10.5%	$3,339.90	$3,702.14	10.8%
40%	100	29,200	$6,728.99	$7,443.12	10.6%	$6,527.74	$7,241.88	10.9%
60%	100	43,800	$10,017.43	$11,083.47	10.6%	$9,715.57	$10,781.61	11.0%
80%	100	58,400	$13,305.91	$14,723.83	10.7%	$12,903.42	$14,321.35	11.0%
20%	200	29,200	$6,830.37	$7,544.62	10.5%	$6,629.12	$7,343.38	10.8%

40%	200	58,400	$13,407.29	$14,825.33	10.6%	$13,004.80	$14,422.85	10.9%
60%	200	87,600	$19,984.19	$22,106.06	10.6%	$19,380.47	$21,502.33	10.9%
80%	200	116,800	$26,561.11	$29,386.77	10.6%	$25,756.14	$28,581.80	11.0%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills June 2025
Tariff Schedule 38, 1-phase Service
Bill comparison assumes 51% on peak and 49% off peak energy consumption Current Prices
Bill comparison assumes 17% on peak 47% mid peak and 36% off peak energy consumption Proposed Prices

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
1,000	$226.63	$259.71	14.6%	$219.74	$252.81	15.1%
3,000	$608.92	$677.62	11.3%	$588.25	$656.94	11.7%
5,000	$991.21	$1,095.53	10.5%	$956.75	$1,061.07	10.9%
7,000	$1,373.49	$1,513.44	10.2%	$1,325.25	$1,465.20	10.6%
10,000	$1,946.93	$2,140.32	9.9%	$1,878.01	$2,071.40	10.3%
13,000	$2,520.36	$2,767.18	9.8%	$2,430.77	$2,677.59	10.2%
14,000	$2,711.51	$2,976.14	9.8%	$2,615.03	$2,879.65	10.1%
16,000	$3,093.80	$3,394.06	9.7%	$2,983.53	$3,283.79	10.1%
21,000	$4,049.52	$4,438.83	9.6%	$3,904.80	$4,294.10	10.0%
25,000	$4,814.10	$5,274.65	9.6%	$4,641.80	$5,102.36	9.9%
30,000	$5,769.82	$6,319.44	9.5%	$5,563.07	$6,112.69	9.9%
35,000	$6,725.55	$7,364.21	9.5%	$6,484.33	$7,123.00	9.8%
40,000	$7,681.26	$8,408.99	9.5%	$7,405.59	$8,133.32	9.8%
45,000	$8,636.98	$9,453.77	9.5%	$8,326.85	$9,143.64	9.8%
50,000	$9,592.71	$10,498.57	9.4%	$9,248.12	$10,153.97	9.8%
75,000	$14,371.33	$15,722.46	9.4%	$13,854.44	$15,205.57	9.8%
100,000	$19,149.95	$20,946.36	9.4%	$18,460.77	$20,257.18	9.7%
150,000	$28,707.18	$31,394.18	9.4%	$27,673.40	$30,360.40	9.7%
200,000	$38,264.41	$41,841.97	9.3%	$36,886.04	$40,463.60	9.7%
300,000	$57,378.88	$62,737.58	9.3%	$55,311.32	$60,670.03	9.7%
400,000	$76,493.34	$83,633.19	9.3%	$73,736.60	$80,876.45	9.7%
500,000	$95,587.80	$104,508.80	9.3%	$92,141.88	$101,062.88	9.7%
750,000	$137,235.07	$151,080.34	10.1%	$132,066.18	$145,911.45	10.5%
1,000,000	$182,801.59	$201,256.85	10.1%	$175,909.74	$194,365.00	10.5%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills June 2025
Tariff Schedule 38, 3-phase Service
Bill comparison assumes 51% on peak and 49% off peak energy consumption Current Prices
Bill comparison assumes 17% on peak 47% mid peak and 36% off peak energy consumption Proposed Prices

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
1,000	$226.63	$269.86	19.1%	$219.74	$262.96	19.7%
3,000	$608.92	$687.77	12.9%	$588.25	$667.09	13.4%
5,000	$991.21	$1,105.68	11.5%	$956.75	$1,071.22	12.0%
7,000	$1,373.49	$1,523.59	10.9%	$1,325.25	$1,475.35	11.3%
10,000	$1,946.93	$2,150.47	10.5%	$1,878.01	$2,081.55	10.8%
13,000	$2,520.36	$2,777.33	10.2%	$2,430.77	$2,687.74	10.6%
14,000	$2,711.51	$2,986.29	10.1%	$2,615.03	$2,889.80	10.5%
16,000	$3,093.80	$3,404.21	10.0%	$2,983.53	$3,293.94	10.4%
21,000	$4,049.52	$4,448.98	9.9%	$3,904.80	$4,304.25	10.2%
25,000	$4,814.10	$5,284.80	9.8%	$4,641.80	$5,112.51	10.1%
30,000	$5,769.82	$6,329.59	9.7%	$5,563.07	$6,122.84	10.1%
35,000	$6,725.55	$7,374.36	9.6%	$6,484.33	$7,133.15	10.0%
40,000	$7,681.26	$8,419.14	9.6%	$7,405.59	$8,143.47	10.0%
45,000	$8,636.98	$9,463.92	9.6%	$8,326.85	$9,153.79	9.9%
50,000	$9,592.71	$10,508.72	9.5%	$9,248.12	$10,164.12	9.9%
75,000	$14,371.33	$15,732.61	9.5%	$13,854.44	$15,215.72	9.8%
100,000	$19,149.95	$20,956.51	9.4%	$18,460.77	$20,267.33	9.8%
150,000	$28,707.18	$31,404.33	9.4%	$27,673.40	$30,370.55	9.7%
200,000	$38,264.41	$41,852.12	9.4%	$36,886.04	$40,473.75	9.7%
300,000	$57,378.88	$62,747.73	9.4%	$55,311.32	$60,680.18	9.7%
400,000	$76,493.34	$83,643.34	9.3%	$73,736.60	$80,886.60	9.7%
500,000	$95,587.80	$104,518.95	9.3%	$92,141.88	$101,073.03	9.7%
750,000	$137,235.07	$151,090.49	10.1%	$132,066.18	$145,921.60	10.5%
1,000,000	$182,801.59	$201,267.00	10.1%	$175,909.74	$194,375.15	10.5%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills June 2025
Tariff Schedule 83, Secondary, 3 phase service.
Bill comparison assumes 63% on peak and 37% off peak energy consumption Current Prices

Bill comparison assumes 19% on peak, 46% mid peak and 35% off peak energy consumption proposed prices

			Net Monthly Billing (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
30%	30	6,570	$1,118.28	$1,233.16	10.3%	$1,073.00	$1,187.88	10.7%
30%	50	10,950	$1,827.95	$2,012.64	10.1%	$1,752.49	$1,937.18	10.5%
30%	63	13,797	$2,289.26	$2,519.30	10.0%	$2,194.18	$2,424.22	10.5%
30%	75	16,425	$2,715.08	$2,986.97	10.0%	$2,601.88	$2,873.76	10.4%
30%	135	29,565	$4,844.16	$5,325.41	9.9%	$4,640.39	$5,121.65	10.4%
30%	175	38,325	$6,263.55	$6,884.36	9.9%	$5,999.41	$6,620.23	10.3%
30%	200	43,800	$7,150.65	$7,858.70	9.9%	$6,848.79	$7,556.83	10.3%
50%	30	10,950	$1,463.41	$1,599.74	9.3%	$1,387.94	$1,524.28	9.8%
50%	50	18,250	$2,403.21	$2,623.57	9.2%	$2,277.43	$2,497.80	9.7%
50%	63	21,250	$2,876.55	$3,143.05	9.3%	$2,730.10	$2,996.59	9.8%
50%	100	36,500	$4,752.71	$5,183.27	9.1%	$4,501.15	$4,931.72	9.6%
50%	135	49,275	$6,397.31	$6,974.99	9.0%	$6,057.71	$6,635.39	9.5%
50%	175	63,875	$8,276.90	$9,022.72	9.0%	$7,836.68	$8,582.50	9.5%
50%	200	73,000	$9,451.63	$10,302.54	9.0%	$8,948.52	$9,799.44	9.5%
70%	30	15,330	$1,808.55	$1,966.32	8.7%	$1,702.90	$1,860.66	9.3%
70%	50	25,550	$2,978.44	$3,234.56	8.6%	$2,802.36	$3,058.47	9.1%
70%	75	38,325	$4,440.80	$4,819.85	8.5%	$4,176.67	$4,555.72	9.1%
70%	100	51,100	$5,903.17	$6,405.15	8.5%	$5,550.99	$6,052.97	9.0%
70%	135	68,985	$7,950.48	$8,624.58	8.5%	$7,475.04	$8,149.15	9.0%
70%	175	89,425	$10,290.22	$11,161.05	8.5%	$9,673.92	$10,544.75	9.0%
70%	200	102,200	$11,752.59	$12,746.36	8.5%	$11,048.24	$12,042.01	9.0%
90%	30	19,710	$2,153.70	$2,332.87	8.3%	$2,017.87	$2,197.03	8.9%
90%	50	32,850	$3,553.67	$3,845.50	8.2%	$3,327.28	$3,619.10	8.8%
90%	75	49,275	$5,303.67	$5,736.28	8.2%	$4,964.07	$5,396.69	8.7%
90%	100	65,700	$7,053.66	$7,627.08	8.1%	$6,600.86	$7,174.29	8.7%
90%	135	88,695	$9,503.59	$10,274.14	8.1%	$8,892.31	$9,662.86	8.7%
90%	175	114,975	$12,303.56	$13,299.40	8.1%	$11,511.17	$12,507.01	8.7%
90%	200	131,400	$14,053.55	$15,190.19	8.1%	$13,147.96	$14,284.59	8.6%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills June 2025
Tariff Schedule 85, Secondary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption Currnet Prices
Bill Comparison assumes 19% on-peak, mid peak 42% and 39% off-peak energy consumption Proposed Prices

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$7,086.98	$7,702.37	8.7%
30%	300	65,700	$10,224.96	$11,096.82	8.5%
30%	500	109,500	$16,500.93	$17,885.68	8.4%
30%	700	153,300	$22,776.87	$24,674.54	8.3%
30%	800	175,200	$25,914.85	$28,068.96	8.3%
30%	900	197,100	$29,052.85	$31,463.41	8.3%
30%	1,000	219,000	$32,190.80	$34,857.82	8.3%
30%	1,500	328,500	$47,880.72	$51,830.01	8.2%
30%	2,000	438,000	$63,570.61	$68,802.15	8.2%
30%	4,000	876,000	$121,295.16	$132,206.36	9.0%
50%	200	73,000	$9,006.87	$9,682.65	7.5%
50%	300	109,500	$13,104.83	$14,067.25	7.3%
50%	500	182,500	$21,300.70	$22,836.41	7.2%
50%	700	255,500	$29,496.54	$31,605.55	7.2%
50%	800	292,000	$33,594.47	$35,990.12	7.1%
50%	900	328,500	$37,692.42	$40,374.72	7.1%
50%	1,000	365,000	$41,790.33	$44,759.26	7.1%
50%	1,500	547,500	$62,210.62	$66,612.77	7.1%
50%	2,000	730,000	$82,510.45	$88,345.86	7.1%
50%	4,000	1,460,000	$156,003.24	$168,489.20	8.0%
70%	200	102,200	$10,926.77	$11,662.94	6.7%
70%	300	153,300	$15,984.67	$17,037.68	6.6%
70%	500	255,500	$26,100.45	$27,787.12	6.5%
70%	700	357,700	$36,216.23	$38,536.58	6.4%
70%	800	408,800	$41,274.10	$43,911.29	6.4%
70%	900	459,900	$46,331.97	$49,286.01	6.4%
70%	1,000	511,000	$51,358.41	$54,629.28	6.4%
70%	1,500	766,500	$72,336.15	$77,672.97	7.4%
70%	2,000	1,022,000	$96,011.17	$103,092.78	7.4%
70%	4,000	2,044,000	$190,711.31	$204,772.04	7.4%
90%	200	131,400	$12,846.69	$13,643.23	6.2%
90%	300	197,100	$18,864.54	$20,008.12	6.1%
90%	500	328,500	$30,900.21	$32,737.86	5.9%
90%	700	459,900	$42,935.87	$45,467.58	5.9%
90%	800	525,600	$48,907.10	$51,785.81	5.9%
90%	900	591,300	$54,856.59	$58,082.36	5.9%
90%	1,000	657,000	$60,806.09	$64,378.89	5.9%
90%	1,500	985,500	$85,351.67	$91,279.03	6.9%
90%	2,000	1,314,000	$113,365.20	$121,234.19	6.9%
90%	4,000	2,628,000	$225,419.39	$241,054.87	6.9%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills June 2025
Tariff Schedule 85, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption
Bill Comparison assumes 19% on-peak, mid peak 42% and 39% off-peak energy consumption Proposed Prices

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$6,893.75	$7,475.99	8.4%
30%	300	65,700	$9,990.86	$10,823.20	8.3%
30%	500	109,500	$16,185.12	$17,517.67	8.2%
30%	700	153,300	$22,379.38	$24,212.08	8.2%
30%	800	175,200	$25,476.49	$27,559.30	8.2%
30%	900	197,100	$28,573.61	$30,906.52	8.2%
30%	1,000	219,000	$31,670.74	$34,253.73	8.2%
30%	1,500	328,500	$47,156.38	$50,989.85	8.1%
30%	2,000	438,000	$62,641.98	$67,725.92	8.1%
30%	4,000	876,000	$119,015.08	$129,651.50	8.9%
50%	200	73,000	$8,783.50	$9,421.75	7.3%
50%	300	109,500	$12,825.52	$13,741.87	7.1%
50%	500	182,500	$20,909.54	$22,382.06	7.0%
50%	700	255,500	$28,993.55	$31,022.25	7.0%
50%	800	292,000	$33,035.54	$35,342.33	7.0%

50%	900	328,500	$37,077.56	$39,662.45	7.0%
50%	1,000	365,000	$41,119.55	$43,982.53	7.0%
50%	1,500	547,500	$61,260.18	$65,513.63	6.9%
50%	2,000	730,000	$81,280.41	$86,924.31	6.9%
50%	4,000	1,460,000	$152,764.07	$164,887.46	7.9%
70%	200	102,200	$10,673.27	$11,367.51	6.5%
70%	300	153,300	$15,660.17	$16,660.48	6.4%
70%	500	255,500	$25,633.94	$27,246.45	6.3%
70%	700	357,700	$35,607.69	$37,832.39	6.2%
70%	800	408,800	$40,594.59	$43,125.37	6.2%
70%	900	459,900	$45,581.48	$48,418.34	6.2%
70%	1,000	511,000	$50,536.92	$53,679.88	6.2%
70%	1,500	766,500	$70,692.09	$75,847.27	7.3%
70%	2,000	1,022,000	$93,856.27	$100,702.48	7.3%
70%	4,000	2,044,000	$186,513.04	$200,123.44	7.3%
90%	200	131,400	$12,563.03	$13,313.25	6.0%
90%	300	197,100	$18,494.79	$19,579.12	5.9%
90%	500	328,500	$30,358.35	$32,110.85	5.8%
90%	700	459,900	$42,221.88	$44,642.54	5.7%
90%	800	525,600	$48,107.01	$50,861.80	5.7%
90%	900	591,300	$53,970.45	$57,059.32	5.7%
90%	1,000	657,000	$59,833.88	$63,256.84	5.7%
90%	1,500	985,500	$83,347.95	$89,060.75	6.9%
90%	2,000	1,314,000	$110,730.76	$118,320.47	6.9%
90%	4,000	2,628,000	$220,262.02	$235,359.40	6.9%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills June 2025
Tariff Schedule 89, Secondary.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption Current Prices
Bill Comparison assumes 18% on-peak, mid peak 40% and 42% off-peak energy consumption Proposed Prices

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$95,455.77	$105,042.81	10.0%
30%	7,500	1,642,500	$174,346.37	$191,695.27	10.0%
30%	10,000	2,190,000	$230,696.76	$253,589.84	9.9%
30%	15,000	3,285,000	$343,397.60	$377,379.04	9.9%
30%	20,000	4,380,000	$446,633.16	$491,691.39	10.1%
50%	4,000	1,460,000	$142,505.63	$154,147.05	8.2%
50%	7,500	2,737,500	$262,564.86	$283,765.70	8.1%
50%	10,000	3,650,000	$348,321.43	$376,350.44	8.0%
50%	15,000	5,475,000	$507,749.54	$549,420.13	8.2%
50%	20,000	7,300,000	$674,896.44	$730,218.01	8.2%
70%	4,000	2,044,000	$189,555.48	$203,251.28	7.2%
70%	7,500	3,832,500	$350,783.35	$375,836.16	7.1%
70%	10,000	5,110,000	$454,734.29	$487,885.54	7.3%
70%	15,000	7,665,000	$678,947.00	$728,315.09	7.3%
70%	20,000	10,220,000	$903,159.71	$968,744.63	7.3%
90%	4,000	2,628,000	$236,605.35	$252,355.53	6.7%
90%	7,500	4,927,500	$428,226.67	$457,118.27	6.7%
90%	10,000	6,570,000	$568,865.93	$607,148.85	6.7%
90%	15,000	9,855,000	$850,144.46	$907,210.06	6.7%
90%	20,000	13,140,000	$1,131,422.99	$1,207,271.26	6.7%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills June 2025
Tariff Schedule 89, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption
Bill Comparison assumes 18% on-peak, mid peak 40% and 42% off-peak energy consumption Proposed Prices

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$94,466.50	$103,898.74	10.0%
30%	7,500	1,642,500	$172,526.99	$189,594.55	9.9%
30%	10,000	2,190,000	$228,284.42	$250,805.80	9.9%
30%	15,000	3,285,000	$339,799.36	$373,228.35	9.8%
30%	20,000	4,380,000	$441,849.01	$486,174.05	10.0%
50%	4,000	1,460,000	$141,019.05	$152,463.57	8.1%
50%	7,500	2,737,500	$259,813.02	$280,653.60	8.0%
50%	10,000	3,650,000	$344,665.80	$372,217.87	8.0%
50%	15,000	5,475,000	$502,286.37	$543,246.65	8.2%
50%	20,000	7,300,000	$667,625.74	$722,003.62	8.1%
70%	4,000	2,044,000	$187,571.59	$201,028.40	7.2%
70%	7,500	3,832,500	$347,099.05	$371,712.65	7.1%
70%	10,000	5,110,000	$449,835.38	$482,404.44	7.2%
70%	15,000	7,665,000	$671,618.92	$720,118.81	7.2%
70%	20,000	10,220,000	$893,402.46	$957,833.18	7.2%
90%	4,000	2,628,000	$234,124.15	$249,593.22	6.6%
90%	7,500	4,927,500	$423,609.92	$451,983.37	6.7%
90%	10,000	6,570,000	$562,723.75	$600,319.22	6.7%
90%	15,000	9,855,000	$840,951.46	$896,990.99	6.7%
90%	20,000	13,140,000	$1,119,179.18	$1,193,662.75	6.7%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Transmission

Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption
Bill Comparison assumes 18% on-peak, mid peak 40% and 42% off-peak energy consumption Proposed Prices

			Net Monthly Bill		
Load Factor	**kW**	**kWh**	**Current Prices**	**Proposed Prices**	**Percent Difference**
30%	4,000	876,000	$89,514.68	$98,163.09	9.7%
30%	5,000	1,095,000	$110,199.55	$120,777.25	9.6%
30%	10,000	2,190,000	$213,623.90	$233,847.99	9.5%
30%	20,000	4,380,000	$411,007.34	$450,512.63	9.6%
30%	40,000	8,760,000	$814,225.73	$892,303.77	9.6%
30%	50,000	10,950,000	$1,015,834.93	$1,113,199.33	9.6%
30%	70,000	15,330,000	$1,419,053.32	$1,554,990.47	9.6%
50%	4,000	1,460,000	$135,564.00	$146,206.30	7.9%
50%	5,000	1,825,000	$167,761.19	$180,831.24	7.8%
50%	10,000	3,650,000	$328,747.20	$353,955.99	7.7%
50%	20,000	7,300,000	$634,267.91	$683,734.06	7.8%
50%	40,000	14,600,000	$1,260,746.87	$1,358,746.61	7.8%
50%	50,000	18,250,000	$1,573,986.35	$1,696,252.89	7.8%
50%	70,000	25,550,000	$2,200,465.31	$2,371,265.44	7.8%
70%	4,000	2,044,000	$181,613.31	$194,249.49	7.0%
70%	5,000	2,555,000	$225,322.85	$240,885.24	6.9%
70%	10,000	5,110,000	$432,658.71	$462,838.49	7.0%
70%	20,000	10,220,000	$857,528.48	$916,955.48	6.9%
70%	40,000	20,440,000	$1,707,268.00	$1,825,189.45	6.9%
70%	50,000	25,550,000	$2,132,137.77	$2,279,306.44	6.9%
70%	70,000	35,770,000	$2,981,877.30	$3,187,540.42	6.9%
90%	4,000	2,628,000	$227,662.63	$242,292.69	6.4%
90%	5,000	3,285,000	$282,884.50	$300,939.24	6.4%
90%	10,000	6,570,000	$544,288.99	$579,449.20	6.5%
90%	20,000	13,140,000	$1,080,789.04	$1,150,176.90	6.4%
90%	40,000	26,280,000	$2,153,789.15	$2,291,632.30	6.4%
90%	50,000	32,850,000	$2,690,289.19	$2,862,360.00	6.4%
90%	70,000	45,990,000	$3,763,289.28	$4,003,815.40	6.4%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills June 2025
Tariff Schedule 90 (30 MWa), Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
80%	3,000	1,752,000	$165,303.72	$182,531.40	10.4%
80%	13,000	7,592,000	$653,444.84	$706,708.34	8.2%
80%	23,000	13,432,000	$1,144,449.56	$1,233,752.36	7.8%
80%	33,000	19,272,000	$1,635,454.27	$1,760,796.39	7.7%
80%	43,000	25,112,000	$2,126,458.98	$2,287,840.42	7.6%
80%	53,000	30,952,000	$2,617,463.68	$2,814,884.45	7.5%
80%	63,000	36,792,000	$3,108,468.40	$3,341,928.48	7.5%
90%	3,000	1,971,000	$182,312.94	$200,456.46	10.0%
90%	13,000	8,541,000	$724,880.98	$782,110.37	7.9%
90%	23,000	15,111,000	$1,270,836.57	$1,367,155.97	7.6%
90%	33,000	21,681,000	$1,816,792.15	$1,952,201.56	7.5%
90%	43,000	28,251,000	$2,362,747.74	$2,537,247.15	7.4%
90%	53,000	34,821,000	$2,908,703.32	$3,122,292.75	7.3%
90%	63,000	41,391,000	$3,454,658.90	$3,707,338.34	7.3%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills June 2025
Tariff Schedule 90 (250 MWa or higher), Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
80%	250,000	146,000,000	$12,032,955.57	$12,470,038.90	3.6%
80%	260,000	151,840,000	$12,513,626.08	$12,967,978.41	3.6%
80%	270,000	157,680,000	$12,994,296.57	$13,465,917.92	3.6%
80%	280,000	163,520,000	$13,474,967.09	$13,963,857.44	3.6%
80%	290,000	169,360,000	$13,955,637.58	$14,461,796.95	3.6%
80%	300,000	175,200,000	$14,436,308.08	$14,959,736.46	3.6%
80%	310,000	181,040,000	$14,916,978.57	$15,457,675.97	3.6%
90%	250,000	164,250,000	$13,374,433.02	$13,829,126.44	3.4%
90%	260,000	170,820,000	$13,908,762.62	$14,381,429.45	3.4%
90%	270,000	177,390,000	$14,443,092.22	$14,933,732.46	3.4%
90%	280,000	183,960,000	$14,977,421.82	$15,486,035.48	3.4%
90%	290,000	190,530,000	$15,511,751.42	$16,038,338.49	3.4%
90%	300,000	197,100,000	$16,046,081.02	$16,590,641.51	3.4%
90%	310,000	203,670,000	$16,580,410.61	$17,142,944.52	3.4%

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2025 COSTS TO RATE SCHEDULES ($000)

	Energy-Based Charges					Trans. & Related Charges			Distribution Demand & Facilities Charges						
Grouping	Power Supply	Franchise Fees	Trojan	Sch 129	Subtotal	Transmission	Ancillary Services	Subtotal	Substation	Subtrans.	Feeder Backbone	Feeder Facilities	Subtotal	Subtotal	Total
Schedule 7	$732,001	$38,781	$844	$265	$39,890	$66,766	$3,436	$70,202	$42,163	$3,600	$108,329	$226,726	$380,819	$1,222,912	$1,510,707
Schedule 15	$877	$108	$1	$0	$109	$63	$4	$67	$69	$6	$190	$225	$489	$1,541	$4,192
Schedule 32	$127,996	$7,146	$148	$52	$7,346	$10,523	$601	$11,124	$6,736	$575	$21,260	$38,492	$67,064	$213,529	$278,378
Schedule 38	$2,158	$135	$2	$1	$138	$180	$10	$191	$169	$14	$553	$1,212	$1,948	$4,435	$5,242
Schedule 47	$1,918	$147	$2	$1	$150	$146	$9	$155	$250	$21	$790	$1,281	$2,343	$4,567	$5,743
Schedule 49	$5,797	$371	$7	$2	$379	$393	$27	$420	$727	$62	$2,384	$2,292	$5,466	$12,062	$14,440
Schedule 83															
Secondary	$232,226	$10,155	$174	$96	$10,425	$18,850	$1,090	$19,941	$12,440	$1,062	$40,790	$35,977	$90,269	$352,861	$395,603
Schedule 85															
Secondary		$6,018	$146	$84	$6,248									$6,248	$21,791
Primary		$2,023	$57	$33	$2,113									$2,113	$4,105
Class Total	$213,033					$16,635	$1,000	$17,635	$12,758	$1,089	$33,886	$9,262	$56,995	$287,663	$287,663
Schedule 89															
Secondary		$0	$0	$0	$0						$0		$0	$0	$0
Primary		$2,577	$201	$80	$2,857						$6,020		$6,020	$8,877	$11,066
Subtransmission		$116	$24	$9	$149						$734		$734	$883	$1,305
Class Total	$77,421					$6,784	$435	$7,219	$7,715	$745			$8,461	$93,100	$93,100
Schedule 90-P	$248,455	$7,529	$287	$124	$7,939	$18,571	$1,191	$19,761	$10,283	$865	$4,509		$15,657	$291,813	$293,369
Schedules 91 & 95	$2,507	$355	$3	$1	$359	$179	$12	$191	$196	$17	$542	$678	$1,433	$4,491	$13,819
Schedules 92	$195	$7	$0	$0	$7	$14	$1	$15	$7	$1	$18	$8	$34	$250	$266
Totals	$1,644,582	$75,467	$1,896	$748	$78,110	$139,104	$7,817	$146,921	$93,513	$8,059	$220,007	$316,153	$637,732	$2,507,346	$2,940,788

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2025 COSTS TO RATE SCHEDULES ($000)

	Dist. Customer-Related TSM		Uncollectibles		Metering		Billing		Other Consumer		Subtotal				Total
Grouping	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Fixed Costs	Subtotal	Cost Allocations
Schedule 7	$149,569.774	$0.000	$10,453.715	$0.000	$1,787.887	$0.000	$42,258.489	$0.000	$83,724.976	$0.000	$287,794.841	$0.000		$287,795	$1,510,707
Schedule 15	$132.965		$42.079		$0.000		$32.535		$20.860		$228.439	$0.000	$2,422.442	$2,651	$4,192
Schedule 32	$20,640.200	$19,581.738	$469.258	$325.530	$245.278	$170.152	$2,662.592	$1,847.072	$11,163.124	$7,743.993	$35,180.453	$29,668.484		$64,849	$278,378
Schedule 38	$20.163	$329.341	$0.014	$0.077	$0.961	$5.095	$2.577	$13.669	$68.931	$365.578	$92.646	$713.760		$806	$5,242
Schedule 47	$29.004	$396.809	$0.695	$6.669	$1.530	$14.672	$10.817	$103.736	$57.763	$553.949	$99.809	$1,075.835		$1,176	$5,743
Schedule 49	$5.306	$677.310	$0.000	$28.261	$0.073	$9.067	$0.619	$76.881	$12.627	$1,568.077	$18.625	$2,359.596		$2,378	$14,440
Schedule 83															
Secondary	$675.150	$19,846.540	$28.164	$338.314	$12.128	$145.685	$61.789	$742.237	$1,605.533	$19,286.291	$2,382.763	$40,359.067		$42,742	$395,603
Schedule 85															
Secondary		$5,805.454		$65.345		$35.530		$121.051		$9,515.423	$0.000	$15,542.802		$15,543	
Primary		$522.833		$9.855		$5.358		$18.256		$1,435.071	$0.000	$1,991.373		$1,991	$313,559
Schedule 89															
Secondary		$0.000		$0.000		$0.000		$0.000		$0.000	$0.000	$0.000		$0	
Primary		$109.444		$0.000		$0.057		$1.850		$2,077.184	$0.000	$2,188.535		$2,189	
Subtransmission		$138.667		$0.000		$0.008		$0.252		$283.252	$0.000	$422.179		$422	$105,472
Schedule 90-P		$17.412		$0.000		$0.009		$0.318		$1,538.413	$0.000	$1,556.151		$1,556	$293,369
Schedules 91 & 95	$953.404			$0.071		$0.000	$63.815		$0.426		$1,017.645	$0.071	$8,310.931	$9,329	$13,819
Schedule 92		$10.360		$0.000		$0.000		$5.157		$0.036	$0.000	$15.553		$16	$266
Totals	$172,025.967	$47,435.907	$10,993.925	$774.121	$2,047.857	$385.633	$45,093.233	$2,930.479	$96,654.240	$44,367.266	$326,815.222	$95,893.407	$10,733.373	$433,442	$2,940,788

Reconcile to Ratespread ($0)

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2025

	Allocated Inputs	Billing Determinants		Rate			Annual Revenue
Schedule	($000)	Amount	Unit	Rate	Unit	c	($000)
SCHEDULE 7							
Residential							
Allocations							
Functional Costs							
Basic Charge							
Single-Phase	$287,795	829,611	Customers	$28.91	per cust. per mo.		$287,809
Three-Phase	$0	0	Customers	$0.00	per cust. per mo.		$0
Trans. & Rel. Serv. Charge	$70,202	7,889,185	MWh	8.90	mills/kWh		$70,214
Distribution Charge	$380,819	7,889,185	MWh	48.27	mills/kWh		$380,811
Franchise Fees & Other	$39,890	7,889,185	MWh	5.06	mills/kWh		$39,919
Energy Charge	$732,001	7,889,185	MWh	92.79	mills/kWh		$732,038
Subtotal	$1,510,707						$1,510,790
Pricing							
Functional Costs							
Basic Charge							
Single-Phase-SFH		583,892		$15.00			$105,100.583
Single-Phase-MFH		245,719		$12.00			$35,383.470
Three-Phase		0	Customers	$15.00	per cust. per mo.		$0.000
Trans. & Rel. Serv. Charge		7,889,185	MWh	8.90	mills/kWh		$70,213.749
Distribution Charge		7,889,185	MWh	66.93	mills/kWh		$528,023.172
System Usage Charge Calculation							
Franchise Fees & Other		7,889,185	MWh	5.06	mills/kWh		$39,919.278
Cust Impact Offset		7,889,185	MWh	0.00	mills/kWh		$0.000
System Usage Charge		7,889,185	MWh	5.06	mills/kWh		$39,919.278
Energy Charge							
Block 1 (First 1,000 kWh)		6,520,978	MWh	92.79	mills/kWh		$605,081.521
Block 2 (Over 1,000 kWh)		1,368,208	MWh	92.79	mills/kWh		$126,955.982
Subtotal					w/ CIO		$1,510,677.755
					w/o CIO		$1,510,677.755
SCHEDULE 15							
Outdoor Area Lighting							
Allocations							
Functional Costs							
Basic Charge	$228	9,254	Customers	$2.06	per cust. per mo.		$228.759
Trans. & Rel. Serv. Charge	$67	13,091	MWh	5.11	mills/kWh		$66.895
Distribution Charge	$489	13,091	MWh	37.34	mills/kWh		$488.818
Franchise Fees & Other	$109	13,091	MWh	8.33	mills/kWh		$109.048
Energy Charge	$877	13,091	MWh	66.97	mills/kWh		$876.704
Fixed Charges	$2,422	13,091	MWh				$2,422.442
Subtotal	$4,192						$4,192.666
Pricing							
Functional Costs							
Trans. & Rel. Serv. Charge		13,091	MWh	5.11	mills/kWh		$66.895
Distribution Charge		13,091	MWh	54.79	mills/kWh		$717.256
System Usage Charge Calc							
Franchise Fees & Other		13,091	MWh	8.33	mills/kWh		$109.048
Cust Impact Offset		13,091	MWh	8.84	mills/kWh		$115.724
System Usage Charge		13,091	MWh	17.17	mills/kWh		$224.772
Energy Charge		13,091	MWh	66.97	mills/kWh		$876.704
Fixed Charges		13,091	MWh				$2,422.442
Subtotal					w/ CIO		$4,308.070
					w/o CIO		$4,192.345
SCHEDULE 32							
General Service <30 kW							
Allocations							
Functional Costs							
Basic Charge							
Single-Phase	$35,180	56,907	Customers	$51.52	per cust. per mo.		$35,181.978
Three-Phase	$29,668	39,477	Customers	$62.63	per cust. per mo.		$29,669.209
Trans. & Rel. Serv. Charge	$11,124	1,550,351	MWh	7.18	mills/kWh		$11,131.518
Distribution Charge	$67,064	1,550,351	MWh	43.26	mills/kWh		$67,068.170
Franchise Fees & Other	$7,346	1,550,351	MWh	4.74	mills/kWh		$7,348.662
Energy Charge	$127,996	1,550,351	MWh	82.56	mills/kWh		$127,996.952
Subtotal	$278,378						$278,396.488
Pricing							
Functional Costs							
Basic Charge							
Single-Phase		56,907	Customers	$24.00	per cust. per mo.		$16,389.120
Three-Phase		39,477	Customers	$33.00	per cust. per mo.		$15,632.826
Trans. & Rel. Serv. Charge		1,550,351	MWh	7.18	mills/kWh		$11,131.518
Distribution Charge							
First 5 MWh		1,361,214	MWh	69.21	mills/kWh		$94,209.596
Over 5 MWh		189,137	MWh	30.00	mills/kWh		$5,674.111
System Usage Charge Calc							
Franchise Fees & Other		1,550,351	MWh	4.74	mills/kWh		$7,348.662
Cust Impact Offset		1,550,351	MWh	0.00	mills/kWh		$0.000
System Usage Charge		1,550,351	MWh	4.74	mills/kWh		$7,348.662
Energy Charge		1,550,351	MWh	82.56	mills/kWh		$127,996.952
Subtotal					w/ CIO		$278,382.785
					w/o CIO		$278,382.785
SCHEDULE 38							
Time-of-Day G.S. >30 kW							
Allocations							
Functional Costs							
Basic							
Single-Phase	$93	56	Customers	$137.87	per cust. per mo.		$92.649
Three-Phase	$714	297	Customers	$200.27	per cust. per mo.		$713.762
Trans. & Rel. Serv. Charge	$191	27,036	MWh	7.05	per cust. per mo.		$190.603
Distribution Charges	$1,948	27,036	MWh	72.07	per cust. per mo.		$1,948.475
Franchise Fees & Other	$138	27,036	MWh	5.10	mills/kWh		$137.883
Energy Charge	$2,158.331	27,036	MWh	79.83	mills/kWh		$2,158.273
Subtotal	$5,242						$5,241.645
Pricing							
Functional Costs							
Basic							
Single-Phase		56	Customers	$50.00	per cust. per mo.		$33.600
Three-Phase		297	Customers	$60.00	per cust. per mo.		$213.840
Trans. & Rel. Serv. Charge		27,036	MWh	7.05	mills/kWh		$190.603
Distribution Charges		27,036	MWh	92.75	mills/kWh		$2,507.577
System Usage Charge							
Franchise Fees & Other		27,036	MWh	5.10	mills/kWh		$137.883

Cust Impact Offset		27,036	MWh	(2.70)	mills/kWh	-$72.997
System Usage Charge		27,036	MWh	2.40	mills/kWh	$64.886
Energy Charge Calc						
On-Peak (special)		4,615	MWh	95.27	mills/kWh	$439.693
Mid-Peak		12,759	MWh	85.27	mills/kWh	$1,087.926
Off-Peak		9,662	MWh	65.27	mills/kWh	$630.641
Reactive Demand Charge		0	kVar	0.50	kVar	$0.000
Subtotal					w/ CIO	$5,168.766
					w/o CIO	$5,241.763

Load Distribution	Mid-C Price ($/MWh)	Marginal Cost ($)	Marginal Cost (%)	Designed Price (mills/kWh)	Price Differentials	Adj Price Differentials
17.1%	98.14	16.75	20.6%	96.41		
47.2%	85.22	40.22	49.5%	83.71	13.0	10
35.7%	67.99	24.30	29.9%	66.79	17.0	20

SCHEDULE 47
Irrig. & Drain. Pump. - < 30 kW

Allocations

Functional Costs						
Basic Charge						
Single-Phase	$100	261	Customers	$63.74	per cust. per sum	$99.817
Three-Phase	$1,076	2,503	Customers	$71.64	per cust. per sum	$1,075.890
Trans. & Rel. Serv. Charge	$155	20,520	MWh	7.57	mills/kWh	$155.339
Distribution Charges	$2,343	20,520	MWh	114.19	mills/kWh	$2,343.219
Franchise Fees & Other	$150	20,520	MWh	7.33	mills/kWh	$150.414
Energy Charge	$1,918	20,520	MWh	93.48	mills/kWh	$1,918.243
Subtotal	$5,742.851					$5,742.921

Pricing

Functional Costs					
Basic Charge					
Single-Phase	261	Customers	$39.00	per cust. per sum	$61.074
Three-Phase	2,503	Customers	$39.00	per cust. per sum	$585.702
Trans. & Rel. Serv. Charge	20,520	MWh	7.57	mills/kWh	$155.339
Distribution Charge Calc					
First 50 kWh per kW	6,340	MWh	153.78	mills/kWh	$974.932
Over 50 kWh per kW	14,181	MWh	133.78	mills/kWh	$1,897.076
System Usage Charge Calc					
Franchise Fees & Other	20,520	MWh	7.33	mills/kWh	$150.414
Cust Impact Offset	20,520	MWh	(13.43)	mills/kWh	-$275.588
System Usage Charge	20,520	MWh	(6.10)	mills/kWh	-$125.174
Energy Charge	20,520	MWh	93.48	mills/kWh	$1,918.243
Reactive Demand Charge	0	kVar	$0.50	kVar	$0.000
Subtotal with Consumer Impact Offset				w/ CIO	$5,467.192
				w/o CIO	$5,742.781

SCHEDULE 49
Irrig. & Drain. Pump. - > 30 kW

Allocations

Functional Costs						
Basic						
Single-Phase	$19	11	Customers	$282.20	per cust. per sum	$18.625
Three-Phase	$2,360	1,366	Customers	$287.90	per cust. per sum	$2,359.628
Trans. & Rel. Serv. Charge	$420	59,354	MWh	7.08	mills/kWh	$420.228
Distribution Charges	$5,466	59,354	MWh	92.08	mills/kWh	$5,465.343
Franchise Fees & Other	$379	59,354	MWh	6.39	mills/kWh	$379.274
Energy Charge	$5,797	59,354	MWh	97.66	mills/kWh	$5,796.539
Subtotal	$14,440					$14,439.638

Pricing

Functional Costs					
Basic Charge					
Single-Phase	11	Customers	$60.00	per cust. per sum	$3.960
Three-Phase	1,366	Customers	$60.00	per cust. per sum	$491.760
Trans. & Rel. Serv. Charge	59,354	MWh	7.08	mills/kWh	$420.228
Distribution Charge Calc					
First 50 kWh per kW	15,298	MWh	138.64	mills/kWh	$2,120.915
Over 50 kWh per kW	44,056	MWh	118.64	mills/kWh	$5,226.837
System Usage Charge Calc					
Franchise Fees & Other	59,354	MWh	6.39	mills/kWh	$379.274
Cust Impact Offset	59,354	MWh	(10.69)	mills/kWh	-$634.497
System Usage Charge	59,354	MWh	(4.30)	mills/kWh	-$255.223
Energy Charge	59,354	MWh	97.66	mills/kWh	$5,796.539
Reactive Demand Charge	0	kVar	0.50	kVar	$0.000
Subtotal with Consumer Impact Offset				w/ CIO	$13,805.017
				w/o CIO	$14,439.514

SCHEDULE 83
General Service 31-200 kW

Allocations

Functional Costs								
Basic Charge								
Single-Phase Secondary	$2,383	908	Customers	$218.76	per cust, per mo.	$2,382.734		
Three-Phase Secondary	$40,359	10,903	Customers	$308.46	per cust, per mo.	$40,358.598		
Transmission & Related Service Charge	$19,941	8,701,974	kW demand	$2.29	per kW demand	$19,927.521		
Distribution Charges								
Feeder Backbone	$40,790	12,302,907	kW faccap	$3.32	per kW faccap	$40,845.653		
Feeder Local Facilities	$35,977	12,302,907	kW faccap	$2.92	per kW faccap	$35,924.490		
Subtransmission Charge	$1,062	8,701,974	kW demand	$0.12	per kW demand	$1,044.237		
Substation Charge	$12,440	8,701,974	kW demand	$1.43	per kW demand	$12,443.823		
Secondary Franchise Fees & Other	$10,425	2,867,544	MWh	3.64	mills/kWh	$10,437.860	Energy %	Capacity %
Secondary COS Energy Charge	$232,226	2,867,544	MWh	80.98	mills/kWh	$232,213.720	65%	35%
Subtotal	$395,603					$395,578.636		

Pricing

Functional Costs					
Basic Charge					
Secondary Single-Phase	908	Customers	$50.00	per cust, per mo.	$544.600
Secondary Three-Phase	10,903	Customers	$60.00	per cust, per mo.	$7,850.340
Trans. & Rel. Serv. Charge					
Peak (On-Peak and Mid-Peak)	8,701,974	kW demand	$2.78	per kW demand	$24,191.489
Off-peak	0	kW demand	$0.00	per kW demand	$0.000
Distribution Charges					
Secondary Facilities Charge					
First 30 kW	4,251,930	kW faccap	$6.31	<= 30 kW faccap	$26,829.678
Over 30 kW	8,050,977	kW faccap	$6.21	> 30 kW faccap	$49,996.570
Secondary Demand Charge					
Peak (On-Peak and Mid-Peak)	8,701,974	kW demand	$1.73	per kW demand	$15,054.416
Off-peak		kW demand	$0.00	per kW demand	$0.000
Secondary System Usage Charge Calc					
Franchise Fees & Other	2,867,544	MWh	3.64	mills/kWh	$10,437.860
Cust Impact Offset	2,867,544	MWh	0.00	mills/kWh	$0.000
Rate Design	2,867,544	MWh	9.80	mills/kWh	$28,101.932
System Usage Charge	2,867,544	MWh	13.44	mills/kWh	$38,539.792
COS Energy Charge					
On-peak	532,264	MWh	63.44	mills/kWh	$33,766.798
Mid-peak	1,310,729	MWh	55.44	mills/kWh	$72,666.841
Off-peak	1,024,551	MWh	43.44	mills/kWh	$44,506.500
Generation Demand Charge (On Peak and Mid-Peak)	8,701,974	kW demand	9.34	per kW demand	$81,276.441
Reactive Demand Charge	757,019	kVar	$0.50	kVar	$378.509
Subtotal				w/ CIO	$395,601.974

Load Distribution	Mid-C Price ($/MWh)	Marginal Cost ($)	Marginal Cost (%)	Designed Price (mills/kWh)	Price Differentials	Adj Price Differentials
18.6%	98.14	18.22	22.4%	63.42		
45.7%	85.22	38.95	47.8%	55.07	8.0	8
35.7%	67.99	24.29	29.8%	43.93	11.0	12

				w/o CIO		$395,601.974

SCHEDULE 85
General Service 201-4,000 kW
Allocations

Functional Costs						
Basic Charge						
Secondary	$15,543	1,472	Customers	$879.91	per cust, per mo.	$15,542.730
Primary	$1,991	222	Customers	$747.51	per cust, per mo.	$1,991.367
Transmission & Related Service Charge	$17,635	7,040,695	kW on-peak	$2.50	per kW demand	$17,601.738
Distribution Charges						
Feeder Backbone	$33,886	11,499,751	kW faccap	$2.95	per kW faccap	$33,924.266
Feeder Local Facilities	$9,262	11,499,751	kW faccap	$0.81	per kW faccap	$9,314.798
Subtransmission Charge	$1,089	8,866,690	kW on-peak	$0.12	per kW on-peak	$1,064.003
Substation Charge	$12,758	8,866,690	kW on-peak	$1.44	per kW on-peak	$12,768.033
Secondary Franchise Fees & Other	$6,248	2,507,579	MWh	2.49	mills/kWh	$6,243.871
Primary Franchise Fees & Other	$2,113	978,435	MWh	2.16	mills/kWh	$2,113.420
COS Energy Charge	$213,033	2,748,209	MWh	77.52	mills/kWh	$213,041.198
Subtotal	$313,559					$313,605.424

Pricing

Functional Costs					
Basic Charge					
Secondary	1,472	Customers	$880.00	per cust, per mo.	$15,544.320
Primary	222	Customers	$750.00	per cust, per mo.	$1,998.000
Secondary Trans. & Rel. Serv. Charge	5,544,150	kW on-peak	$2.78	per kW demand	$15,412.737
Primary Trans. & Rel. Serv. Charge	1,496,545	kW on-peak	$2.75	per kW demand	$4,115.499
Distribution Charges					
Secondary Facilities Charge					
First 200 kW	3,532,800	kW faccap	$3.47	per kW faccap	$12,258.816
Over 200 kW	5,220,801	kW faccap	$3.37	per kW faccap	$17,594.100
Primary Facilities Charge					
First 200 kW	532,800	kW faccap	$3.43	per kW faccap	$1,827.504
Over 200 kW	2,213,350	kW faccap	$3.33	per kW faccap	$7,370.455
Secondary Demand Charge	6,667,343	kW on-peak	$1.73	per kW demand	$11,534.504
Primary Demand Charge	2,199,347	kW on-peak	$1.71	per kW demand	$3,760.883
Secondary System Usage Charge Calc					
COS Franchise Fees & Other	2,074,490	MWh	2.88	mills/kWh	$5,974.533
Cust Impact Offset	2,074,490	MWh	0.00	mills/kWh	$0.000
COS System Usage Charge	2,074,490	MWh	2.88	mills/kWh	$5,974.533
DA Franchise Fees & Other	433,088	MWh	0.65	mills/kWh	$281.507
Cust Impact Offset	433,088	MWh	0.00	mills/kWh	$0.000
DA System Usage Charge	433,088	MWh	0.65	mills/kWh	$281.507
Primary System Usage Charge Calc					
COS Franchise Fees & Other	673,719	MWh	2.85	mills/kWh	$1,920.099
Cust Impact Offset	673,719	MWh	0.00	mills/kWh	$0.000
COS System Usage Charge	673,719	MWh	2.85	mills/kWh	$1,920.099
DA Franchise Fees & Other	304,716	MWh	0.65	mills/kWh	$198.065
Cust Impact Offset	304,716	MWh	0.00	mills/kWh	$0.000
DA System Usage Charge	304,716	MWh	0.65	mills/kWh	$198.065
Secondary COS Energy Charge					
On-peak	360,557	MWh	61.55	mills/kWh	$22,192.261
Mid-peak	960,108	MWh	53.55	mills/kWh	$51,413.767
Off-peak	753,826	MWh	41.55	mills/kWh	$31,321.477
Generation Demand Charge	5,544,150	kW on-peak	10.62	per kW demand	$58,878.871
Primary COS Energy Charge					
On-peak	125,072	MWh	61.00	mills/kWh	$7,629.408
Mid-peak	286,035	MWh	53.00	mills/kWh	$15,159.858
Off-peak	262,612	MWh	41.00	mills/kWh	$10,767.078
Generation Demand Charge	1,496,545	kW on-peak	10.50	per kW demand	$15,713.725
Reactive Demand Charge	1,434,492	kVar	0.50	kVar	$717.246
Subtotal					$313,584.714
				w/o CIO	$313,584.714

SCHEDULE 89 GT 4,000 kW
General Service
Allocations

Functional Costs								
Secondary Basic Charge	$0	0	Customers	$4,190.83	per cust, per mo.	$0.000		
Primary Basic Charge	$2,189	44	Customers	$4,144.95	per cust, per mo.	$2,188.534		
Subtransmission Basic Charge	$422	6	Customers	$5,863.60	per cust, per mo.	$422.179		
Transmission & Related Service Charge	$7,219	2,028,635	kW on-peak	$3.56	per kW on-peak	$7,221.942		
Distribution Charges								
Feeder Backbone	$6,754	4,957,690	kW faccap	$1.36	per kW faccap	$6,742.459		
Feeder Local Facilities						$0.000		
Subtransmission Demand Charge	$745	4,783,996	kW on-peak	$0.16	per kW on-peak	$765.439		
Substation Demand Charge	$7,715	4,166,703	kW on-peak	$1.85	per kW on-peak	$7,708.400		
Secondary Franchise Fees & Other	$0	0	MWh	1.21	mills/kWh	$0.000		
Primary Franchise Fees & Other	$2,857	2,377,164	MWh	1.20	mills/kWh	$2,852.597	Secondary Losses	1.06
Subtransmission Franchise Fees & Other	$149	282,282	MWh	0.53	mills/kWh	$149.609	Primary Losses	1.05
Energy Charge	$77,421	1,057,276	MWh	73.23	mills/kWh	$77,424.290	Delta Losses	0.01
Subtotal	$105,472					$105,475.449		

Pricing

Functional Costs					
Secondary Basic Charge	0	Customers	$4,190.00	per cust, per mo.	$0.000
Primary Basic Charge	44	Customers	$4,140.00	per cust, per mo.	$2,185.920
Subtransmission Basic Charge	6	Customers	$5,860.00	per cust, per mo.	$421.920
Secondary Trans. & Rel. Serv. Charge	0	kW on-peak	$2.78	per kW on-peak	$0.000
Primary Trans. & Rel. Serv. Charge	1,883,218	kW on-peak	$2.75	per kW on-peak	$5,178.849
Subtransmission Trans. & Rel. Serv. Charge	145,418	kW on-peak	$2.70	per kW on-peak	$392.627
Distribution Charges					
Secondary Facilities Charge					
First 1,000 kW	0	kW faccap	$2.04	per kW faccap	$0.000
Greater than 4,000 kW	0	kW faccap	$1.73	per kW faccap	$0.000
Primary Facilities Charge					
First 4,000 kW	2,112,000	kW faccap	$2.02	per kW faccap	$4,266.240
Greater than 4,000 kW	1,969,363	kW faccap	$1.71	per kW faccap	$3,367.611
Subtransmission Facilities Charge					
First 4,000 kW	288,000	kW faccap	$2.00	per kW faccap	$576.000
Greater than 4,000 kW	400,327	kW faccap	$1.69	per kW faccap	$676.553
Secondary Demand Charge	0	kW on-peak	$1.73	per kW on-peak	$0.000
Primary Demand Charge	4,166,703	kW on-peak	$1.71	per kW on-peak	$7,125.062
Subtransmission Demand Charge	617,293	kW on-peak	$0.13	per kW on-peak	$80.248
Secondary System Usage Charge Calc					
COS Franchise Fees & Other	0	MWh	2.44	mills/kWh	$0.000
Cust Impact Offset	0	MWh	0.00	mills/kWh	$0.000
COS System Usage Charge	0	MWh	2.44	mills/kWh	$0.000
DA Franchise Fees & Other	0	MWh	0.30	mills/kWh	$0.000
Cust Impact Offset	0	MWh	0.00	mills/kWh	$0.000
DA System Usage Charge	0	MWh	0.30	mills/kWh	$0.000
Primary System Usage Charge Calc					
COS Franchise Fees & Other	1,024,681	MWh	2.41	mills/kWh	$2,469.482
Cust Impact Offset	1,024,681	MWh	0.00	mills/kWh	$0.000
COS System Usage Charge	1,024,681	MWh	2.41	mills/kWh	$2,469.482
DA Franchise Fees & Other	1,352,483	MWh	0.29	mills/kWh	$392.220

	Cust Impact Offset		1,352,483	MWh	0.00	mills/kWh	$0.000		
	DA System Usage Charge		1,352,483	MWh	0.29	mills/kWh	$392.220		
	Subtransmission System Usage Charge Calc								
	COS Franchise Fees & Other		32,594	MWh	2.38	mills/kWh	$77.575		
	Cust Impact Offset		32,594	MWh	0.00	mills/kWh	$0.000		
	COS System Usage Charge		32,594	MWh	2.38	mills/kWh	$77.575		
	DA Franchise Fees & Other		249,687	MWh	0.29	mills/kWh	$72.409		
	Cust Impact Offset		249,687	MWh	0.00	mills/kWh	$0.000		
	DA System Usage Charge		249,687	MWh	0.29	mills/kWh	$72.409		
	Secondary Energy Charge								
	On-peak		0	MWh	85.53	mills/kWh	$0.000		
	Mid-peak		0	MWh	77.53	mills/kWh	$0.000		
	Off-peak		0	MWh	65.53	mills/kWh	$0.000		
	Primary Energy Charge								
	On-peak		189,020	MWh	84.73	mills/kWh	$16,015.651		
	Mid-peak		408,883	MWh	76.73	mills/kWh	$31,373.602		
	Off-peak		426,778	MWh	64.73	mills/kWh	$27,625.353		
	Subtransmission Energy Charge								
	On-peak		5,109	MWh	83.91	mills/kWh	$428.693		
	Mid-peak		18,492	MWh	75.91	mills/kWh	$1,403.708		
	Off-peak		8,994	MWh	63.91	mills/kWh	$574.787		
	Reactive Demand Charge		1,564,310	kVar	0.50	kVar	$782.155		
	Subtotal					w/ CIO	$105,486.666		
						w/o CIO	$105,486.666		
SCHEDULE 90									
Primary Voltage Service									
Allocations									
	Functional Costs								
	Primary Basic Charge	$1,556	7	Customers	$18,525.61	per cust, per mo.	$1,556.151		
	Subtransmission Basic Charge		0	Customers	$18,525.61	per cust, per mo.	$0.000		
	Transmission & Related Service Charge	$19,761	5,553,283	kW on-peak	$3.56	per kW on-peak	$19,769.687		
	Distribution Charges								
	Feeder Backbone	$4,509	5,634,359	kW faccap	$0.80	per kW faccap	$4,507.488		
	Subtransmission Demand Charge	$865	5,553,283	kW on-peak	$0.16	per kW on-peak	$888.525		
	Substation Demand Charge	$10,283	5,553,283	kW on-peak	$1.85	per kW on-peak	$10,273.573		
	Primary Franchise Fees & Other	$7,939	3,685,313	MWh	2.15	mills/kWh	$7,923.422	Primary Losses	1.05
	Subtransmission Franchise Fees & Other		0	MWh	2.17	mills/kWh	$0.000	Sub Trans Losses	1.04
	Energy Charge	$248,454.674	3,685,313	MWh	67.42	mills/kWh	$248,463.773	Delta Losses	0.01
	Subtotal	$293,368.720					$293,382.618		
Pricing									
	Functional Costs								
	Primary Basic Charge		7	Customers	$18,500.00	per cust, per mo.	$1,554.000		
	Subtransmission Basic Charge		0	Customers	$18,500.00	per cust, per mo.	$0.000		
	Primary Trans. & Rel. Serv. Charge		5,553,283	kW on-peak	$2.75	per kW on-peak	$15,271.528		
	Subtransmission Trans & Rel Serv. Charge		0	kW on-peak	$2.70	per kW on-peak	$0.000		
	Distribution Charges								
	Primary Facilities Charge								
	First 4,000 kW		336,000	kW faccap	$2.05	per kW faccap	$688.800		
	Over 4,000 kW		5,298,359	kW faccap	$1.74	per kW faccap	$9,219.145		
	Subtransmission Facilities Charge								
	First 4,000 kW		0	kW faccap	$2.05	per kW faccap	$0.000		
	Over 4,000 kW		0	kW faccap	$1.74	per kW faccap	$0.000		
	Primary Demand Charge		5,553,283	kW on-peak	$1.71	per kW on-peak	$9,496.113		
	Subtransmission Demand Charge		0	kW on-peak	$0.13	per kW on-peak	$0.000		
	Primary System Usage Charge Calc >250MWa								
	COS Franchise Fees & Other		3,122,187	MWh	2.15	mills/kWh	$6,712.702		
	Cust Impact Offset		3,122,187	MWh	0.27	mills/kWh	$842.990		
	COS System Usage Charge		3,122,187	MWh	2.42	mills/kWh	$7,555.692		
	Primary System Usage Charge Calc 30-250 Mwa								
	COS Franchise Fees & Other		563,126	MWh	2.15	mills/kWh	$1,210.720		
	Cust Impact Offset		563,126	MWh	0.27	mills/kWh	$152.044		
	COS System Usage Charge		563,126	MWh	2.42	mills/kWh	$1,362.764		
	Subtransmission System Usage Charge Calc >250MWa								
	COS Franchise Fees & Other		0	MWh	2.15		$0.000		
	Cust Impact Offset		0	MWh	0.27		$0.000		
	COS System Usage Charge		0	MWh	2.42	mills/kWh	$0.000		
	Subtransmission System Usage Charge Calc 30-250MWa								
	COS Franchise Fees & Other		0	MWh	2.15		$0.000		
	Cust Impact Offset		0	MWh	0.27		$0.000		
	COS System Usage Charge		0	MWh	2.42	mills/kWh	$0.000		
	Primary Energy Charge 30-250MWa								
	On-peak		323,349	MWh	78.00	mills/kWh	$25,221.201		
	Off-peak		239,777	MWh	63.00	mills/kWh	$15,105.956		
	Primary Energy Charge >250Mwa								
	On-peak		1,790,596	MWh	73.09	mills/kWh	$130,874.691		
	Off-peak		1,331,590	MWh	58.09	mills/kWh	$77,352.084		
	Subtransmission Energy Charge 30-250MWa								
	On-peak		0	MWh	76.73	mills/kWh	$0.000	106.17%	Sch 90 30-250 Mwa differential
	Off-peak		0	MWh	60.81	mills/kWh	$0.000		
	Subtransmission Energy Charge >250MWa								
	On-peak		0	MWh	72.27	mills/kWh	$0.000		
	Off-peak		0	MWh	57.27	mills/kWh	$0.000		
	Reactive Demand Charge		1,329,267	kVar	$0.50	kVar	$664.634		
						w/CIO	$294,366.608		
						w/o CIO	$293,371.573		
SCHEDULES 91 & 95									
Street & Highway Lighting									
Allocations									
	Functional Costs								
	Basic Charge	$1,018	189	Customers	$448.70	per cust, per mo.	$1,017.652		
	Trans. & Rel. Serv. Charge	$191	37,437	MWh	5.11	mills/kWh	$191.303		
	Distribution Charge	$1,433	37,437	MWh	38.28	mills/kWh	$1,433.088		
	Franchise Fees & Other	$359	37,437	MWh	9.59	mills/kWh	$359.021		
	COS Energy Charge	$2,507	37,437	MWh	66.97	mills/kWh	$2,507.156		
Pricing	Fixed Charges	$8,311					$8,310.931		
	Fur Subtotal	$13,819					$13,819.151		
	Trans. & Rel. Serv. Charge		37,437	MWh	5.11	mills/kWh	$191.303		
	Distribution Charge		37,437	MWh	65.46	mills/kWh	$2,450.626		
	System Usage Charge Calc								
	Franchise Fees & Other		37,437	MWh	9.59	mills/kWh	$359.021		
	Cust Impact Offset		37,437	MWh	(3.09)	mills/kWh	-$115.680		
	System Usage Charge		37,437	MWh	6.50	mills/kWh	$243.341		
	COS Energy Charge		37,437	MWh	66.97	mills/kWh	$2,507.156		
SCHEDULE 92	Fixed Charges		37,437	MWh			$8,310.931		
Traffic Signals	Subtotal					w/ CIO	$13,703.356		
Allocations									
	Functional Costs					w/o CIO	$13,819.037		

	Basic Charge	$16	16	Customers	$81.01	per cust, per mo.	$15.554
	Trans. & Rel. Serv. Charge	$15	2,724	MWh	5.43	mills/kWh	$14.791
	Distribution Charge	$34	2,724	MWh	12.30	mills/kWh	$33.505
	Franchise Fees & Other	$7	2,724	MWh	2.62	mills/kWh	$7.137
Pricing	COS Energy Charge	$195	2,724	MWh	71.55	mills/kWh	$194.902
	Fur Subtotal	$266					$265.890

	Trans. & Rel. Serv. Charge	2,724	MWh	5.43	mills/kWh	$14.791
	Distribution Charge	2,724	MWh	18.02	mills/kWh	$49.086
	System Usage Charge Calc					
	Franchise Fees & Other	2,724	MWh	2.62	mills/kWh	$7.137
	Cust Impact Offset	2,724	MWh	0.00	mills/kWh	$0.000
	System Usage Charge	2,724	MWh	2.62	mills/kWh	$7.137
	COS Energy Charge	2,724	MWh	71.55	mills/kWh	$194.902
	Subtotal				w/ CIO	$265.917
Summary of Inputs						
	Functional Costs				w/o CIO	$265.917

	Allocated Inputs	DesSumm	Deltas
Basic Charge	$422,708.558	$422,708.629	($0)
Trans. & Rel. Serv. Charge	$146,921.460	$146,921.460	$0
Distribution Charge	$637,732.050	$637,732.050	$0
Fixed Charges	$10,733.373	$10,733.373	$0
Franchise Fees & Other	$78,110.440	$78,110.440	$0
Energy Charge	$1,644,582.496	$1,644,582.496	$0
Subtotal	$2,940,788.376	$2,940,788.447	

Functional Costs Revenues	Annual Revenue	Revenue	Deltas		
Basic Charge	$203,995.035	$203,995.035	$0		
Trans. & Rel. Serv. Charge	$146,947.155	$146,947.155	$0		
Distribution Charges	$825,573.883	$825,573.883	$0		
Fixed Charges	$10,733.373	$10,733.372	($0)		
System Usage Charge	$106,271.817	$106,271.817	$0		
Energy Charge	$1,644,755.011	$1,644,719.864	($35)	($35)	(Voluntary TOU)
Reactive	$2,542.544	$2,542.544	$0		
Subtotal	$2,940,818.819	$2,940,783.671	($35.148)	($35)	

Note: figures are before employee discount and Schedule 129

On-peak demand	27,905,943	27,905,943	0
Facility Capacity	34,206,708	34,206,708	0
kVar	5,085,089	5,085,089	0

$2,930,085 w/o Sch 15/91/95 fixed charges
$2,940,819 w/ CIO
$2,940,807 w/o CIO

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at Current Prices ($000)	2025 Allocated Costs ($000)	Percent Change	Impact Offset Amount	Impact Offset MWH	CIO mills/kWh	CIO Revenues
Schedule 7	7,889,185	$1,547,541	$1,542,500	-0.3%		7,889,185	0.00	$0
Schedule 15	13,091	$4,258	$4,231	-0.6%			8.84	$116
Schedule 32	1,550,351	$284,566	$283,959	-0.2%		1,550,351	0.00	$0
Schedule 38	27,036	$5,210	$5,336	2.4%		27,036	(2.70)	($72.997)
Schedule 47	20,520	$5,373	$5,825	8.4%		20,520	(13.43)	($275.588)
Schedule 49	59,354	$13,526	$14,691	8.6%		59,354	(10.69)	($634)
Schedule 83	2,867,544	$402,681	$405,725	0.8%		2,867,544	0.00	$0
Schedule 85	2,748,209	$332,293.65	$323,905.52	-2.5%		2,748,209	0.00	$0
Schedule 89/75	1,057,276	$114,048.01	$107,046	-6.1%		1,057,276	0.00	$0
Schedule 90	3,685,313	$72,393	$295,092	307.6%		3,685,313	0.27	$995.034
Schedules 91 & 95	37,437	$13,668	$13,930	1.9%			(3.09)	($116)
Schedule 92	2,724	$284	$274	-3.5%			0.00	$0
COS TOTALS	19,958,040							
Sch 485 Energy	737,804					737,804	0.00	$0
Sch 489 Energy	1,345,834						0.00	$0
Sch 689 Energy	256,336						0.00	$0
Totals	22,298,015	$2,795,842	$3,002,516	7.4%	$0	20,642,592		$12

Note: does not include Sch 76R	$0	$0
Note: does not include employee discount	($1,043)	($1,086)
Reconcile CIO worksheet to revenues	$2,794,799	$3,001,429
	$2,766,047	$3,011,068
	28,752	(9,639)

Schedules	CIO Allocation	MWh	CIO (mills/kWh)
38	-$72,870.54	27,036	-2.7
47	-$275,509.28	20,520	-13.43
49	-$634,216.12	59,354	-10.69
83		2,867,544	0
85/485/585		3,486,014	0
89/489/589/689		2,659,446	0
90/490/590	$982,596	3,685,313	0.27
Totals	0	9,830,772	

PORTLAND GENERAL ELECTRIC
2025 Test Period Functionalized Revenue Requirement

Function	Amount	Spread
PRODUCTION	$1,646,994	$1,646,994
TRANSMISSION	$139,349	$139,349
ANCILLARY	$7,831	$7,831
DISTRIBUTION	$958,075	$958,075
METERING	$2,439	$2,439
BILLING	$48,131	$48,131
CONSUMER	$141,336	$141,336
TOTALS	$2,944,155	$2,944,155
Schedule 129		$748
Schedule 139		$0
Employee Discount		$1,118
Partial Requirements Transmission		$0
Partial Requirements Distribution		$0
Spread Total		$2,946,021

Note: Employee discount is allocated to distribution

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2025 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$733,560	$732,486
Net Variable Power Costs	$913,434	$912,097
Production Costs	$1,646,994	$1,644,582
Ancillary Services	$7,831	$7,817
Transmission		
Transmission	$139,349	
Partial Requirements Daily Demand	$0	
Transmission Costs	$139,349	$139,104
Distribution Services	$958,075	
Franchise	($75,635)	
Uncollectibles	($11,794)	
Trojan Decommissioning	($1,900)	
Partial Requirements Daily Demand	$0	
Employee Discount	$1,118	$1,118
Distribution Costs	$869,863	$867,927
Consumer Services		
Metering Services	$2,439	$2,433
Billing Services	$48,131	$48,024
Other Consumer Services	$141,336	$141,022
Franchise Fees	$75,635	$75,467
Uncollectibles	$11,794	$11,768
Trojan Decommissioning	$1,900	$1,896
Schedule 129	$748	$748
Schedule 139	$0	$0
Totals	$2,946,021	$2,940,789
Net of employee discount	$2,944,903	$2,939,671
Net of Sch 129 and Sch 139	$2,944,155	$2,938,923
Calendar MWH (COS & ESS)	22,347,745	
Cycle MWH (COS & ESS)	22,298,015	
Cycle/Cal Ratio	99.78%	
COS Calendar Energy MWH	19,993,214	
COS Cycle MWH	19,958,040	
Cycle/Cal Ratio	99.82%	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF GENERATION REVENUE REQUIREMENT TO COS CUSTOMERS
2025

Schedules	COS Calendar Energy	Marginal Energy Costs ($000)	Marginal Energy Allocation	Marginal Capacity Costs ($000)	Marginal Capacity Allocation	Marginal Energy & Capacity Costs ($000)	Energy & Capacity Allocation Percent	Allocation of Load Following Adjs. ($000)	Allocated Energy & Capacity Costs ($000)	Cycle Basis Costs ($000)	Cycle Basis Percent	Capacity Percent	Energy Percent
Schedule 7	7,884,216	$644,220	39.9%	$471,316	51.01%	$1,115,536	43.96%	$7,524	$731,539	$732,001	44.5%	42.3%	57.7%
Schedule 15	13,091	$924	0.1%	$426	0.05%	$1,351	0.05%	$0	$877	$876.73	0.1%	31.6%	68.4%
Schedule 32	1,552,078	$126,210	7.8%	$68,949	7.46%	$195,160	7.69%	$1,474	$128,139	$127,996	7.8%	35.3%	64.7%
Schedule 38	27,056	$2,227	0.1%	$1,061	0.11%	$3,288	0.13%	$26	$2,160	$2,158	0.1%	32.3%	67.7%
Schedule 47	21,235	$1,892	0.1%	$1,133	0.12%	$3,025	0.12%	$22	$1,985	$1,918	0.1%	37.5%	62.5%
Schedule 49	58,622	$5,334	0.3%	$3,391	0.37%	$8,725	0.34%	$62	$5,725	$5,797	0.4%	38.9%	61.1%
Schedule 83	2,870,725	$233,784	14.5%	$120,211	13.01%	$353,995	13.95%	$2,730	$232,484	$232,226	14.1%	34.0%	66.0%
Schedule 85	2,751,490	$222,329	13.8%	$102,295	11.07%	$324,624	12.79%	$2,597	$213,287	$213,033	13.0%	31.5%	68.5%
Schedule 89/75	1,068,811	$84,406	5.2%	$34,664	3.75%	$119,069	4.69%	$986	$78,265	$77,421	4.7%	29.1%	70.9%
Schedule 90	3,705,728.156	$289,409	17.9%	$119,282	12.91%	$408,690	16.11%	($15,421)	$249,831	$248,455	15.1%	29.2%	70.8%
Schedule 91/95	37,437	$2,644	0.2%	$1,219	0.13%	$3,863	0.15%	$0	$2,507	$2,507	0.2%	31.6%	68.4%
Schedule 92	2,724	$217	0.0%	$83	0.01%	$300	0.01%	$0	$195	$195	0.0%	27.7%	72.3%
TOTAL	19,993,214	$1,613,595	100.0%	$924,030	100.0%	$2,537,625	100.00%	$0	$1,646,994	$1,644,582		36.4%	63.6%
4-Hour Battery				$237.36			**TARGET**		**$1,646,994**				
Projected Peak Load				3,893									
Marginal Capacity Costs ($000)				$924,030									

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT

Schedules	12 CP MW	Unit Marginal Cost	Marginal Cost	Transmission Allocation Percent	Class Revenue Requirement
Schedule 7	1,587.7	$87.34	$138,673	48.00%	$66,766
Schedule 15	1.5	$87.34	$130	0.05%	$63
Schedule 32	250.2	$87.34	$21,855	7.56%	$10,523
Schedule 38	4.3	$87.34	$375	0.13%	$180
Schedule 47	3.5	$87.34	$303	0.11%	$146
Schedule 49	9.3	$87.34	$817	0.28%	$393
Schedule 83	448.3	$87.34	$39,152	13.55%	$18,850
Schedule 85	395.6	$87.34	$34,552	11.96%	$16,635
Schedule 89	139.8	$87.34	$12,211	4.23%	$5,879
Schedule 90-P	463.1	$87.34	$40,450	14.00%	$19,475
Schedules 91/95	4.3	$87.34	$373	0.13%	$179
Schedule 92	0.3	$87.34	$29	0.01%	$14
Totals	3,308.0		$288,921		
Target				100.00%	$139,104
Unit Marginal Cost $/kW		**$87.34**			

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE REVENUE REQUIREMENT
2025

Schedules	Production Allocation Percent	Class Revenue Requirement
Schedule 7	43.96%	$3,436
Schedule 15	0.05%	$4
Schedule 32	7.69%	$601
Schedule 38	0.13%	$10
Schedule 47	0.12%	$9
Schedule 49	0.34%	$27
Schedule 83	13.95%	$1,090
Schedule 85	12.79%	$1,000
Schedule 89	4.69%	$367
Schedule 90-P	16.11%	$1,259
Schedules 91/95	0.15%	$12
Schedule 92	0.01%	$1
TOTAL	100.00%	$7,817
	TARGET	$7,817

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2025

Schedules	Cycle Generation Revenues (000s)	Allocation Percent	Class Revenue Requirement	COS + DA MWh	mills/kWh
Schedule 7	$732,001	44.55%	$844	7,889,185	0.11
Schedule 15	$877	0.05%	$1.011	13,091	0.08
Schedule 32	$127,996	7.79%	$148	1,550,351	0.10
Schedule 38	$2,158	0.13%	$2	27,036	0.09
Schedule 47	$1,918	0.12%	$2	20,520	0.11
Schedule 49	$5,797	0.35%	$7	59,354	0.11
Schedule 83	$150,947	9.19%	$174	2,867,544	0.06
Schedule 85-S	$126,347	7.69%	$146	2,507,579	0.06
Schedule 89-S	$0	0.00%	$0	0	0.00
Schedule 85-P	$49,299	3.00%	$57	978,435	0.06
Schedule 89-P	$174,071	10.59%	$201	2,377,164	0.08
Schedule 89-T	$20,671	1.26%	$24	282,282	0.08
Schedule 90-P	$248,455	15.12%	$287	3,685,313	0.08
Schedule 91/95	$2,507	0.15%	$3	37,437	0.08
Schedule 92	$195	0.01%	$0	2,724	0.08
TOTAL	$1,643,238		$1,896	22,298,015	
		TARGET	$1,896		

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2025

Schedules	Distribution Allocations	Transmission Allocations	Generation Allocations	Schedule 129/139 Allocations	Subtotal Allocations	Distribution Fran. Fee Allocations	Transmission Fran. Fee Allocations	Generation Fran. Fee Allocations	Schedule 129/139 Fran. Fee Allocations	Total Fran. Fee Allocations
Schedule 7	$669,458	$70,202	$732,001		$1,471,661	$17,641	$1,850	$19,289		$38,781
Schedule 15	$3,141	$67	$877		$4,084	$83	$2	$23		$108
Schedule 32	$132,060	$11,124	$127,996		$271,180	$3,480	$293	$3,373		$7,146
Schedule 38	$2,757	$191	$2,158		$5,106	$73	$5	$57		$135
Schedule 47	$3,521	$155	$1,918		$5,595	$93	$4	$51		$147
Schedule 49	$7,850	$420	$5,797		$14,067	$207	$11	$153		$371
Schedule 83	$133,185	$19,941	$232,226		$385,352	$3,510	$525	$6,120		$10,155
Schedule 85	$74,732	$17,635	$213,033	$1,084	$306,484	$1,969	$465	$5,614	($6)	$8,042
Schedule 89	$18,050	$7,219	$77,421	($1,832)	$100,858	$476	$190	$2,040	($13)	$2,693
Schedule 90	$17,500	$19,761	$248,455		$285,716	$461	$521	$6,547		$7,529
Schedules 91/95	$10,765	$191	$2,507		$13,463	$284	$5	$66		$355
Schedule 92	$49	$15	$195		$259	$1	$0	$5		$7
TOTALS	$1,073,070	$146,921	$1,644,582	($748)	$2,863,826	$28,277	$3,872	$43,338	($20)	$75,467

Franchise Fee Revenue Requirement **$75,467**

Schedules	Distribution MWh	Distribution mills/kWh	Transmission MWh	Transmission mills/kWh	Generation MWh	Generation mills/kWh	Schedule 129/139 MWh	Schedule 129/139 mills/kWh	Total COS mills/kWh	Total DA mills/kWh	Difference COS/DA mills/kWh		
Schedule 7	7,889,185	2.2361	7,889,185	0.2345	7,889,185	2.4451	0.0		4.916				
Schedule 15	13,091	6.32	13,091	0.13	13,091	1.76	0		8.22	6.32	1.90	1.90	(melded lighting)
Schedule 32	1,550,351	2.24	1,550,351	0.19	1,550,351	2.18	0		4.61	2.24	2.36		
Schedule 38	27,036	2.69	27,036	0.19	27,036	2.10	0		4.98	2.69	2.29		
Schedule 47	20,520	4.52	20,520	0.20	20,520	2.46	0		7.18				
Schedule 49	59,354	3.49	59,354	0.19	59,354	2.57	0		6.25	3.49	2.76		
Schedule 83	2,867,544	1.22	2,867,544	0.18	2,867,544	2.13	0		3.54	1.22	2.32		
Schedule 85-S	2,507,579	0.57	2,074,490	0.17	2,074,490	2.05	433,088	(0.01)	2.78	0.5583	2.23		
Schedule 89-S	0	0.18	0	0.18	0	1.95	0	(0.01)	2.31	0.17	2.14		
Schedule 85-P	978,435	0.56	673,719	0.17	673,719	2.03	304,716	(0.01)	2.75	0.55	2.20		
Schedule 89-P	2,377,164	0.18	1,024,681	0.18	1,024,681	1.93	1,352,483	(0.01)	2.29	0.17	2.12		
Schedule 89-T/75-T	282,282	0.18	32,594	0.18	32,594	1.91	249,687	(0.01)	2.26	0.17	2.09		
Schedule 90-P	3,685,313	0.13	3,685,313	0.14	3,685,313	1.78			2.04	0.13	1.92		
Schedule 90-T	0	0.13	0	0.14	0	1.78			2.04	0.13	1.92		
Schedule 91/95	37,437	7.58	37,437	0.13	37,437	1.76	0		9.48	7.58	1.90		
Schedule 92	2,724	0.48	2,724	0.14	2,724	1.89	0		2.51	0.48	2.03		
TOTALS	22,298,015		19,958,040		19,958,040		2,339,975						

Voltage Differentials

Sch 85 Secondary/PrimaryDelta	1.107%	0.01	0.00	0.02
Secondary/PrimaryDelta	1.107%	0.00	0.00	0.02
Secondary/Subtransmission Delta	2.243%	0.00	0.00	0.04
Prim/Subtransmission Delta	1.136%	0.00		

Revenues

Schedules	MWh	Fran. Fee mills/kWh	Fran. Fee Revenues
Schedule 7	7,889,185	4.92	$38,780.9
Schedule 15	13,091	8.22	$107.6
Schedule 32	1,550,351	4.61	$7,146.1
Schedule 38	27,036	4.98	$134.6
Schedule 47	20,520	7.18	$147.4
Schedule 49	59,354	6.25	$370.7
Schedule 83	2,867,544	3.54	$10,154.7
Schedule 85-S	2,074,490	2.78	$5,776.4
Schedule 485-S	433,088	0.56	$241.8
Schedule 89-S	0	2.31	$0.0
Schedule 489-S	0	0.17	$0.0
Schedule 85-P	673,719	2.75	$1,855.3
Schedule 485-P	304,716	0.55	$168.2
Schedule 89-P	1,024,681	2.29	$2,345.89
Schedule 489-P	1,352,483	0.17	$230.80
Schedule 89-T/75-T	32,594	2.26	$73.8
Schedule 489-T	249,687	0.17	$42.1
Schedule 90-P	3,685,313	2.04	$7,529.1
Schedule 90-T	0	2.04	$0.0
Schedule 91/95	37,437	9.48	$354.8
Schedule 92	2,724	2.51	$6.825
TOTALS	22,298,015		$75,466.84

ALLOCATION OF TRANSITION ADJUSTMENT

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 7	7,889,185	35.4%	$265	0.03
Schedule 15	13,091	0.1%	$0	0.03
Schedule 32	1,550,351	7.0%	$52	0.03
Schedule 38	27,036	0.1%	$1	0.03
Schedule 47	20,520	0.1%	$1	0.03
Schedule 49	59,354	0.3%	$2	0.03
Schedule 83	2,867,544	12.9%	$96	0.03
Schedule 85-S	2,507,579	11.2%	$84	0.03
Schedule 89-S	0	0.0%	$0	0.03
Schedule 85-P	978,435	4.4%	$33	0.03
Schedule 89-P	2,377,164	10.7%	$80	0.03
Schedule 89-T/75-T	282,282	1.3%	$9	0.03
Schedule 90-P	3,685,313	16.5%	$124	0.03
Schedules 91/95	37,437	0.2%	$1	0.03
Schedule 92	2,724	0.0%	$0	0.03
TOTAL	22,298,015	100.00%	$748	0.03
		TARGET	$748	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2025

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	88.83%	$10,454
Three Phase	0.00%	$0
Schedule 15		
Residential	0.16%	$18
Commercial	0.20%	$24
Schedule 32		
Single Phase	3.99%	$469
Three Phase	2.77%	$326
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.00%	$0
Schedule 47		
Single Phase	0.01%	$1
Three Phase	0.06%	$7
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.24%	$28
Schedule 83		
Single Phase	0.24%	$28
Three Phase	2.87%	$338
Schedule 85		
Secondary	0.56%	$65
Primary	0.08%	$10
Schedule 89		
Secondary	0.00%	$0
Primary	0.00%	$0
Subtransmission	0.00%	$0
Schedule 90-P	0.00%	$0
Schedules 91/95	0.00%	$0
Schedule 92	0.00%	$0
TOTAL	100.00%	$11,768
	TARGET	$11,768

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2025

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	829,611	Customers	$21.08	$17,488.193	$22,933.74
		Three-Phase Customers	0	Customers	$47.38	$0.000	$0.00
	Transformer & Service						
		Single-Phase Customers	829,611	Customers	$116.40	$96,566.682	$126,636.03
		Three-Phase Customers	0	Customers	$154.70	$0.000	$0.00
FACILITIES	Feeder Backbone						
		Single-Phase Customers	2,024,669	kW, rateclass peak	$40.80	$82,606.495	$108,328.86
		Three-Phase Customers	0	kW, rateclass peak	$40.80	$0.000	$0.00
	Feeder Local Facilities						
		Single-Phase Customers	3,318,443	Design Demand	$52.10	$172,890.880	$226,726.39
		Three-Phase Customers	0	Design Demand	$52.10	$0.000	$0.00
DEMAND	Subtransmission		2,064,292	kW, rateclass peak	$1.33	$2,745.508	$3,600.42
	Substation		2,024,669	kW, rateclass peak	$15.88	$32,151.744	$42,163.29
SUBTOTAL						$404,449.502	$530,388.7358
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		6,747	Lights	$1.53	$10.318	$14
	Transformer & Service		6,747	Lights	$3.28	$22.130	$29
FACILITIES	Feeder Backbone		404	kW, rateclass peak	$43.89	$17.732	$23
	Feeder Local Facilities		404	Design Demand	$52.03	$21.020	$28
DEMAND	Subtransmission		412	kW, rateclass peak	$1.33	$0.548	$1
	Substation		404	kW, rateclass peak	$15.88	$6.416	$8
FIXED	Luminaires & Poles						$297
SUBTOTAL						$78.164	$400
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		14,336	Lights	$1.53	$21.923	$29
	Transformer & Service		14,336	Lights	$3.28	$47.022	$62
FACILITIES	Feeeder Backbone		2,890	kW, rateclass peak	$43.89	$126.842	$166
	Feeder Local Facilities		2,890	Design Demand	$52.03	$150.367	$197
DEMAND	Subtransmission		2,947	kW, rateclass peak	$1.33	$3.919	$5
	Substation		2,890	kW, rateclass peak	$15.88	$45.893	$60
FIXED	Luminaires & Poles						$2,125
SUBTOTAL						$395.966	$2,644
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$42
	Transformer & Service						$91
FACILITIES	Feeeder Backbone						$190

	Feeder Local Facilities					$225
DEMAND	Subtransmission					$6
	Substation					$69
FIXED	Luminaires & Poles					**$2,422**
SUBTOTAL						$3,044
Schedule 32 Small Non-residential General Service						
CUSTOMER	Meters					
	Single-Phase Customers	56,907	Customers	$43.59	$2,480.562	$3,253
	Three-Phase Customers	39,477	Customers	$61.01	$2,408.482	$3,158
	Transformer & Service					
	Single-Phase Customers	56,907	Customers	$232.99	$13,258.684	$17,387
	Three-Phase Customers	39,477	Customers	$317.24	$12,523.631	$16,423
FACILITIES	Feeder Backbone					
	Single-Phase Customers	119,884	kW, rateclass peak	$50.12	$6,008.584	$7,880
	Three-Phase Customers	203,582	kW, rateclass peak	$50.12	$10,203.532	$13,381
	Feeder Local Facilities					
	Single-Phase Customers	256,080	Design Demand	$78.67	$20,145.814	$26,419
	Three-Phase Customers	438,193	Design Demand	$21.01	$9,206.435	$12,073
DEMAND	Subtransmission	329,797	kW, rateclass peak	$1.33	$438.630	$575
	Substation	323,466	kW, rateclass peak	$15.88	$5,136.640	$6,736
SUBTOTAL					$81,810.993	$107,286
Schedule 38 General Service						
CUSTOMER	Meters					
	Single-Phase Customers	56	Customers	$50.04	$2.802	$4
	Three-Phase Customers	297	Customers	$100.38	$29.813	$39
	Transformer & Service					
	Single-Phase Customers	56	Customers	$224.52	$12.573	$16
	Three-Phase Customers	297	Customers	$745.21	$221.327	$290
FACILITIES	Feeder Backbone					
	Single-Phase Customers	436	kW, rateclass peak	$52.07	$22.683	$30
	Three-Phase Customers	7,668	kW, rateclass peak	$52.07	$399.293	$524
	Feeder Local Facilities					
	Single-Phase Customers	2,358	Design Demand	$93.12	$219.577	$288
	Three-Phase Customers	30,175	Design Demand	$23.35	$704.586	$924
DEMAND	Subtransmission	8,263	kW, rateclass peak	$1.33	$10.990	$14
	Substation	8,104	kW, rateclass peak	$15.88	$128.692	$169
SUBTOTAL					$1,752.335	$2,298
Schedule 47 Irrigation & Drainage Service - < 30 kW						
CUSTOMER	Meters					
	Single-Phase Customers	261	Customers	$50.54	$13.191	$17
	Three-Phase Customers	2,503	Customers	$70.05	$175.335	$230
	Transformer & Service					
	Single-Phase Customers	261	Customers	$34.20	$8.926	$12
	Three-Phase Customers	2,503	Customers	$50.84	$127.253	$167
FACILITIES	Feeder Backbone					
	Single-Phase Customers	788	kW, rateclass peak	$50.12	$39.504	$52
	Three-Phase Customers	11,236	kW, rateclass peak	$50.12	$563.139	$738

	Feeder Local Facilities					
	Single-Phase Customers	2,714	Design Demand	$73.97	$200.755	$263
	Three-Phase Customers	39,297	Design Demand	$19.75	$776.116	$1,018
DEMAND	Subtransmission	12,259	kW, rateclass peak	$1.33	$16.304	$21
	Substation	12,024	kW, rateclass peak	$15.88	$190.941	$250
SUBTOTAL					$2,111.464	$2,769
Schedule 49 Irrigation & Drainage Service - > 30 kW						
CUSTOMER	Meters					
	Single-Phase Customers	11	Customers	$50.54	$0.556	$1
	Three-Phase Customers	1,366	Customers	$60.83	$83.094	$109
	Transformer & Service					
	Single-Phase Customers	11	Customers	$317.26	$3.490	$5
	Three-Phase Customers	1,366	Customers	$317.27	$433.391	$568
FACILITIES	Feeder Backbone					
	Single-Phase Customers	279	kW, rateclass peak	$52.07	$14.525	$19
	Three-Phase Customers	34,641	kW, rateclass peak	$52.07	$1,803.760	$2,365
	Feeder Local Facilities					
	Single-Phase Customers	406	Design Demand	$89.70	$36.418	$48
	Three-Phase Customers	76,086	Design Demand	$22.49	$1,711.174	$2,244
DEMAND	Subtransmission	35,603	kW, rateclass peak	$1.33	$47.352	$62
	Substation	34,920	kW, rateclass peak	$15.88	$554.530	$727
SUBTOTAL					$4,688.289	$6,148
Schedule 83 General Service (31-200 kW)						
CUSTOMER	Meters					
	Single-Phase Customers	908	Customers	$50.54	$45.873	$60
	Three-Phase Customers	10,903	Customers	$105.82	$1,153.782	$1,513
	Transformer & Service					
	Single-Phase Customers	908	Customers	$516.67	$468.964	$615
	Three-Phase Customers	10,903	Customers	$1,282.21	$13,980.256	$18,333
FACILITIES	Feeder Backbone					
	Single-Phase Customers	29,201	kW, rateclass peak	$52.07	$1,520.473	$1,994
	Three-Phase Customers	568,160	kW, rateclass peak	$52.07	$29,584.114	$38,796
	Feeder Local Facilities					
	Single-Phase Customers	50,194	Design Demand	$93.12	$4,674.065	$6,129
	Three-Phase Customers	974,751	Design Demand	$23.35	$22,760.436	$29,848
DEMAND	Subtransmission	609,051	kW, rateclass peak	$1.33	$810.038	$1,062
	Substation	597,361	kW, rateclass peak	$15.88	$9,486.093	$12,440
SUBTOTAL					$84,484.095	$110,791
Schedule 85 General Service (201-4,000 kW)						
CUSTOMER	Meters					
	Secondary Customers	1,472	Customers	$113.81	$167.528	$220
	Primary Customers	222	Customers	$1,795.89	$398.688	$523
	Transformer & Service					
	Secondary Customers	1,472	Customers	$2,893.64	$4,259.438	$5,586
	Primary Customers	222	Customers	$0.00	$0.000	$0
FACILITIES	Feeder Backbone	612,614	kW, rateclass peak	$42.18	$25,840.059	$33,886
	Feeder Local Facilities	958,296	Design Demand	$7.37	$7,062.642	$9,262

DEMAND	Subtransmission	624,603	kW, rateclass peak	$1.33	$830.722	$1,089
	Substation	612,614	kW, rateclass peak	$15.88	$9,728.310	$12,758
SUBTOTAL					$48,287.386	$63,323
Schedule 89 General Service (4,000 plus kW)						
CUSTOMER	Meters					
	Secondary Meters	0	Customers	$113.81	$0.000	$0
	Primary Meters	44	Customers	$1,896.75	$83.457	$109
	Substation Meters	6	Customers	$17,623.44	$105.741	$139
	Transformer & Service					
	Secondary Customers	0	Customers	$0.00	$0.000	$0
	Primary Customers	44	Customers	$0.00	$0.000	$0
FACILITIES	Feeder Backbone					
	Secondary Customers	0	Customers	$104,332.00	$0.000	$0
	Primary Customers	44	Customers	$104,332.00	$4,590.608	$6,020
	Subtransmission 115 kV Feed	6	Customers	$93,301.00	$559.806	$734
DEMAND	Subtransmission	407,333	kW, rateclass peak	$1.33	$541.753	$710
	Substation (Sec. & Prim. Only)	357,927	kW, rateclass peak	$15.88	$5,683.881	$7,454
SUBTOTAL					$11,565.245	$15,166
Schedule 90 Primary Voltage Service						
CUSTOMER	Meters					
	Primary Meters	7	Customers	$1,896.75	$13.277	$17
FACILITIES	Feeder Backbone					
	Primary Customers	7	Customers	$491,171.00	$3,438.197	$4,509
DEMAND	Subtransmission	516,260	kW, rateclass peak	$1.33	$686.626	$900
	Substation (Sec. & Prim. Only)	506,351	kW, rateclass peak	$15.88	$8,040.854	$10,545
SUBTOTAL					$12,178.954	$15,971
Schedules 91 & 95 Streetlighting & Highway Lighting						
CUSTOMER	Customer Service	151,172	Lights	$1.53	$231.177	$303
	Transformer & Service	151,172	Lights	$3.28	$495.844	$650
FACILITIES	Feeder Backbone	9,421	kW, rateclass peak	$43.89	$413.488	$542
	Feeder Local Facilities	9,421	Design Demand	$54.88	$517.024	$678
DEMAND	Subtransmission	9,606	kW, rateclass peak	$1.33	$12.776	$17
	Substation	9,421	kW, rateclass peak	$15.88	$149.605	$196
FIXED	Luminaires & Poles					**$8,311**
SUBTOTAL					$1,819.915	$10,698
Schedule 92 Traffic Signals						
CUSTOMER	Transformer & Service	1,248	Intersections	$6.33	$7.900	$10
FACILITIES	Feeder Backbone	318	kW, rateclass peak	$43.89	$13.957	$18
	Feeder Local Facilities	318	Design Demand	$19.25	$6.122	$8
DEMAND	Subtransmission	324	kW, rateclass peak	$1.33	$0.431	$1
	Substation	318	kW, rateclass peak	$15.88	$5.050	$7

SUBTOTAL				$33.459	$44

Summary

CUSTOMER	Meters	944,050	Customers	$24,650	$32,326
	Transformer & Service		Customers	$142,438	$186,790
	Customer Service	172,255	Lights	$263	$345
FACILITIES	Feeder Backbone	3,626,191	kW, rateclass peak	$167,767	$220,007
	Feeder Local Facilities	6,160,026	Design Demand	$241,083	$316,153
DEMAND	Subtransmission	4,620,750	kW, rateclass peak	$6,146	$8,059
	Substation	4,490,469	kW rateclass peak	$71,309	$93,513
FIXED	Luminaires & Poles				$10,733
TOTALS				$653,656	$867,927
				TARGET	$867,927
			EQUAL PERCENT		131.1%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2025

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	829,611	$0.25	$207.403	$1,788
Three Phase	0	$0.25	$0.000	$0
Schedule 15				
Residential	4,044	$0.00	$0.000	$0
Commercial	5,210	$0.00	$0.000	$0
Schedule 32				
Single Phase	56,907	$0.50	$28.453	$245
Three Phase	39,477	$0.50	$19.738	$170
Schedule 38				
Single Phase	56	$1.99	$0.111	$1
Three Phase	297	$1.99	$0.591	$5
Schedule 47				
Single Phase	261	$0.68	$0.177	$2
Three Phase	2,503	$0.68	$1.702	$15
Schedule 49				
Single Phase	11	$0.77	$0.008	$0
Three Phase	1,366	$0.77	$1.052	$9
Schedule 83				
Single Phase	908	$1.55	$1.407	$12
Three Phase	10,903	$1.55	$16.900	$146
Schedule 85				
Secondary	1,472	$2.80	$4.122	$36
Primary	222	$2.80	$0.622	$5
Schedule 89				
Secondary	0	$0.15	$0.000	$0
Primary	44	$0.15	$0.007	$0
Subtransmission	6	$0.15	$0.001	$0
Schedule 90-P	7	$0.15	$0.001	$0
Schedules 91/95	189	$0.00	$0.000	$0
Schedule 92	16	$0.00	$0.000	$0
TOTAL	953,509		$282.295	$2,433.489
			TARGET	$2,433
		EQUAL PERCENT		862.0366%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2025

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	829,611	$22.59	$18,741	$42,258
Three Phase	0	$22.59	$0	$0
Schedule 15				
Residential	4,044	$1.79	$7	$16
Commercial	5,210	$1.38	$7	$16
Schedule 32				
Single Phase	56,907	$20.75	$1,181	$2,663
Three Phase	39,477	$20.75	$819	$1,847
Schedule 38				
Single Phase	56	$20.41	$1	$3
Three Phase	297	$20.41	$6	$14
Schedule 47				
Single Phase	261	$18.38	$5	$11
Three Phase	2,503	$18.38	$46	$104
Schedule 49				
Single Phase	11	$24.96	$0	$1
Three Phase	1,366	$24.96	$34	$77
Schedule 83				
Single Phase	908	$30.19	$27	$62
Three Phase	10,903	$30.19	$329	$742
Schedule 85				
Secondary	1,472	$36.47	$54	$121
Primary	222	$36.47	$8	$18
Schedule 89				
Secondary	0	$18.65	$0	$0
Primary	44	$18.65	$1	$2
Subtransmission	6	$18.65	$0	$0
Schedule 90-P	7	$20.14	$0	$0
Schedules 91/95	189	$149.74	$28	$64
Schedule 92	16	$142.95	$2	$5
TOTAL	953,509		$21,298	$48,024
			TARGET	$48,024
		EQUAL PERCENT		225%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2025

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	829,611	$37.16	$30,828	$83,725
Three Phase	0	$37.16	$0	$0
Schedule 15				
Residential	4,044	$0.83	$3	$9
Commercial	5,210	$0.83	$4	$12
Schedule 32				
Single Phase	56,907	$72.23	$4,110	$11,163
Three Phase	39,477	$72.23	$2,851	$7,744
Schedule 38				
Single Phase	56	$453.23	$25	$69
Three Phase	297	$453.23	$135	$366
Schedule 47				
Single Phase	261	$81.49	$21	$58
Three Phase	2,503	$81.49	$204	$554
Schedule 49				
Single Phase	11	$422.68	$5	$13
Three Phase	1,366	$422.68	$577	$1,568
Schedule 83				
Single Phase	908	$651.31	$591	$1,606
Three Phase	10,903	$651.31	$7,101	$19,286
Schedule 85				
Secondary	1,472	$2,380.21	$3,504	$9,515
Primary	222	$2,380.21	$528	$1,435
Schedule 89				
Secondary	0	$17,382.70	$0	$0
Primary	44	$17,382.70	$765	$2,077
Subtransmission	6	$17,382.70	$104	$283
Schedule 90-P	7	$80,922.59	$566	$1,538
Schedule 91/95	189	$0.83	$0	$0
Schedule 92	16	$0.83	$0	$0
TOTAL	953,509		$51,925.459	$141,021.506
			TARGET	$141,021.506
		EQUAL PERCENT		$2.716

PORTLAND GENERAL ELECTRIC

PROPOSED
Summary of Area and Streetlighting Revenue

Schedule 15 - Area Lighting	
Fixtures & Maintenance	$1,658,567
Poles	$768,778
Energy (volumetric c/kWh rate)	$1,636,202
Total	**$4,063,546**

Schedule 91/95 - Street and Highway Lighting	
Fixtures & Maintenance (Options A&B)	$4,954,695
Poles (Options A&B)	$3,356,037
Energy (volumetric c/kWh rate)	$5,642,237
Total	**$13,952,969**

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	DAX Sch 91 & 95 A & B RATES A	B	C	TOTAL	Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	B	Annual Energy
79	Cobrahead - PD	HPS	70-watt	30	Standard	$0.00	$0.00	$4.32	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
84	Cobrahead - PD	HPS	100-watt	43	Standard	$0.00	$0.90	$6.19	$0.00	$3.91	$3.01		-	-	4	4	2	$0	$0	$297
85	Cobrahead - PD	HPS	150-watt	62	Standard	$0.00	$0.00	$8.93	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
89	Cobrahead - PD	HPS	200-watt	79	Standard	$0.00	$0.94	$11.38	$0.00	$6.47	$0.00		-	-	-	0	0	$0	$0	$0
86	Cobrahead - PD	HPS	250-watt	102	Standard	$0.00	$0.00	$14.69	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
87	Cobrahead - PD	HPS	400-watt	163	Standard	$0.00	$0.95	$23.48	$0.00	$12.37	$11.42		-	-	1	1	2	$0	$0	$282
33	Cobrahead	HPS	70-watt	30	Standard	$6.16	$1.16	$4.32	$8.26	$3.26	$2.10		1	33	309	343	123	$74	$459	$17,781
34	Cobrahead	HPS	100-watt	43	Standard	$5.34	$1.08	$6.19	$8.35	$4.09	$3.01		34	600	157	791	408	$2,179	$7,776	$58,755
35	Cobrahead	HPS	150-watt	62	Standard	$0.00	$1.09	$8.93	$0.00	$5.43	$4.34		-	120	195	315	234	$0	$1,570	$33,755
39	Cobrahead	HPS	200-watt	79	Standard	$0.00	$1.14	$11.38	$0.00	$6.67	$5.53		-	581	289	870	825	$0	$7,948	$118,807
36	Cobrahead	HPS	250-watt	102	Standard	$0.00	$1.13	$14.69	$0.00	$8.28	$7.15		-	472	117	589	721	$0	$6,400	$103,829
37	Cobrahead	HPS	400-watt	163	Standard	$5.70	$1.12	$23.48	$17.12	$12.54	$11.42		8	69	154	231	452	$547	$927	$65,087
31	Flood	HPS	250-watt	102	Standard	$0.00	$1.32	$14.69	$0.00	$8.47	$7.15		-	-	1	1	1	$0	$0	$176
32	Flood	HPS	400-watt	163	Standard	$0.00	$1.29	$23.48	$0.00	$12.71	$11.42		-	-	16	16	31	$0	$0	$4,508
40	Post-Top	HPS	100-watt	43	Standard	$0.00	$1.24	$6.19	$0.00	$4.25	$3.01		-	1,567	343	1,910	986	$0	$23,317	$141,875
76	Shoebox	HPS	70-watt	30	Standard	$0.00	$1.15	$4.32	$0.00	$3.25	$2.10		-	66	14	80	29	$0	$911	$4,147
77	Shoebox	HPS	100-watt	43	Standard	$0.00	$1.21	$6.19	$0.00	$4.22	$3.01		-	331	1,312	1,643	848	$0	$4,806	$122,042
78	Shoebox	HPS	150-watt	62	Standard	$0.00	$1.26	$8.93	$0.00	$5.60	$4.34		-	44	85	129	96	$0	$665	$13,824
81	Special Acorn	HPS	100-watt	43	Custom	$0.00	$1.68	$6.19	$0.00	$4.69	$3.01		-	757	241	998	515	$0	$15,261	$74,131
82	Victorian	HPS	150-watt	62	Custom	$0.00	$1.69	$8.93	$0.00	$6.03	$4.34		-	369	211	580	432	$0	$7,483	$62,153
49	Victorian	HPS	200-watt	79	Custom	$0.00	$1.54	$11.38	$0.00	$7.07	$5.53		-	78	3	81	77	$0	$1,441	$11,061
83	Victorian	HPS	250-watt	102	Custom	$0.00	$1.54	$14.69	$0.00	$8.69	$7.15		-	566	9	575	704	$0	$10,460	$101,361
64	Capitol Acorn	HPS	100-watt	43	Custom	$0.00	$1.95	$6.19	$0.00	$4.96	$3.01		-	13	7	20	10	$0	$304	$1,486
67	Capitol Acorn	HPS	150-watt	62	Custom	$0.00	$1.87	$8.93	$0.00	$6.21	$4.34		-	363	28	391	291	$0	$8,146	$41,900
65	Capitol Acorn	HPS	200-watt	79	Custom	$0.00	$1.98	$11.38	$0.00	$7.51	$0.00		-	60	-	60	57	$0	$1,426	$8,194
66	Capitol Acorn	HPS	250-watt	102	Custom	$0.00	$0.00	$14.69	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
12	Acorn - Indep.	HPS	100-watt	43	Custom	$0.00	$1.63	$6.19	$0.00	$4.64	$3.01		-	1	22	23	12	$0	$20	$1,708
13	Acorn - Indep.	HPS	150-watt	62	Custom	$0.00	$0.00	$8.93	$0.00	$0.00	$4.34		-	-	8	8	6	$0	$0	$857
98	Techtra	HPS	100-watt	43	Custom	$0.00	$0.00	$6.19	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
99	Techtra	HPS	150-watt	62	Custom	$0.00	$0.00	$8.93	$0.00	$0.00	$4.34		-	-	4	4	3	$0	$0	$429
88	Techtra	HPS	250-watt	102	Custom	$0.00	$2.37	$14.69	$0.00	$9.52	$0.00		-	37	-	37	45	$0	$1,052	$6,522
90	Westbrooke Acorn	HPS	70-watt	30	Custom	$0.00	$1.77	$4.32	$0.00	$3.87	$0.00		-	43	-	43	15	$0	$913	$2,229
91	Westbrooke Acorn	HPS	100-watt	43	Custom	$0.00	$1.76	$6.19	$0.00	$4.77	$3.01		-	365	4	369	190	$0	$7,709	$27,409
92	Westbrooke Acorn	HPS	150-watt	62	Custom	$0.00	$1.95	$8.93	$0.00	$6.29	$0.00		-	25	-	25	19	$0	$585	$2,679
93	Westbrooke Acorn	HPS	200-watt	79	Custom	$0.00	$0.99	$11.38	$0.00	$6.52	$0.00		-	1	-	1	1	$0	$12	$137
94	Westbrooke Acorn	HPS	250-watt	102	Custom	$0.00	$1.74	$14.69	$0.00	$8.89	$0.00		-	24	-	24	29	$0	$501	$4,231
62	Cobrahead	MH	150-watt	60	Custom	$0.00	$0.00	$8.64	$0.00	$0.00	$4.20		-	-	28	28	20	$0	$0	$2,903
61	Flood	MH	350-watt	139	Custom	$0.00	$0.00	$20.02	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
47	Flood	HPS	750-watt	285	Custom	$0.00	$0.00	$41.05	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
18	Ornamental Acorn Twin / Opt C	QL	85-watt	64	Custom	$0.00	$0.00	$9.22	$0.00	$0.00	$4.48		-	-	441	441	339	$0	$0	$48,792
20	Ornamental Acorn / Opt C	QL	55-watt	21	Custom	$0.00	$0.00	$3.02	$0.00	$0.00	$1.47		-	-	2	2	1	$0	$0	$72
26	Ornamental Acorn Twin / Opt C	QL	55-watt	42	Custom	$0.00	$0.00	$6.05	$0.00	$0.00	$2.94		-	-	15	15	8	$0	$0	$1,089
44	Composite Twin / Opt C	Comp	140-watt	54	Custom	$0.00	$0.00	$7.78	$0.00	$0.00	$3.78		-	-	41	41	27	$0	$0	$3,828
45	Composite Twin / Opt C	Comp	175-watt	66	Custom	$0.00	$0.00	$9.51	$0.00	$0.00	$4.62		-	-	100	100	79	$0	$0	$11,412
19	Cobrahead - (C) Only	MV	100-watt	39	Obsolete	$0.00	$0.00	$5.62	$0.00	$0.00	$2.73		-	-	1	1	0	$0	$0	$67
21	Cobrahead	MV	175-watt	66	Obsolete	$0.00	$1.07	$9.51	$0.00	$5.69	$4.62		-	83	68	151	120	$0	$1,066	$17,232
22	Cobrahead	MV	250-watt	94	Obsolete	$0.00	$0.00	$13.54	$0.00	$0.00	$6.59		-	-	23	23	26	$0	$0	$3,737
23	Cobrahead	MV	400-watt	147	Obsolete	$0.00	$0.00	$21.17	$0.00	$0.00	$10.30		-	-	75	75	132	$0	$0	$19,053
24	Cobrahead	MV	1,000-watt	374	Obsolete	$5.78	$1.20	$53.87	$31.98	$27.40	$26.20		1	1	3	5	22	$69	$14	$3,232
9	Mongoose	HPS	150-watt	62	Obsolete	$0.00	$1.67	$8.93	$0.00	$6.01	$0.00		-	10	-	10	7	$0	$200	$1,072
10	Mongoose	HPS	250-watt	102	Obsolete	$0.00	$1.80	$14.69	$0.00	$8.95	$0.00		-	8	-	8	10	$0	$173	$1,410
50	Special Box - Space-Glo	HPS	70-watt	30	Obsolete	$6.49	$0.00	$4.32	$8.59	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
46	Special Box - Space-Glo	MV	175-watt	66	Obsolete	$0.00	$1.15	$9.51	$0.00	$5.77	$4.62		-	92	23	115	91	$0	$1,270	$13,124
51	Box - Gardco Hub / Opt C	HPS	Twin 70-watt	60	Obsolete	$0.00	$0.00	$8.64	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
52	Box - Gardco Hub / Opt C	HPS	70-watt	30	Obsolete	$0.00	$0.00	$4.32	$0.00	$0.00	$2.10		-	-	30	30	11	$0	$0	$1,555
53	Box - Gardco Hub	HPS	100-watt	43	Obsolete	$0.00	$0.00	$6.19	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
54	Box - Gardco Hub	HPS	150-watt	62	Obsolete	$0.00	$0.00	$8.93	$0.00	$0.00	$4.34		-	-	14	14	10	$0	$0	$1,500
55	Box - Gardco Hub / Opt C	HPS	250-watt	102	Obsolete	$0.00	$0.00	$14.69	$0.00	$0.00	$7.15		-	-	3	3	4	$0	$0	$529
56	Box - Gardco Hub / Opt C	HPS	400-watt	163	Obsolete	$0.00	$0.00	$23.48	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
58	Box - Gardco Hub	MH	250-watt	99	Obsolete	$0.00	$0.95	$14.26	$0.00	$7.89	$6.94		-	1	6	7	8	$0	$11	$1,198

PORTLAND GENERAL ELECTRIC

Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum				Monthly		Tariff Rates		Monthly	DAX Sch 91 & 95 A & B RATES				Proposed Sch 91 & 95 A & B Counts				Annual	Annual Fixed Revenue		Annual
CODE	Light Description	Type	Watts	kWh	Category	A	B	Energy	A	B	C	TOTAL	A	B	C	TOTAL	MWh	A	B	Energy
59	Box - Gardco Hub	MH	400-watt	156	Obsolete	$0.00	$0.00	$22.47	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
48	Cobrahead	MH	175-watt	71	Obsolete	$0.00	$0.00	$10.23	$0.00	$0.00	$4.97		-	-	22	22	19	$0	$0	$2,701
60	Flood	MH	400-watt	156	Obsolete	$0.00	$0.00	$22.47	$0.00	$0.00	$10.93		-	-	10	10	19	$0	$0	$2,696
69	Cobrahead DW 70/100	HPS	100-watt	43	Obsolete	$0.00	$0.00	$6.19	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
70	Cobrahead DW 100/150	HPS	100-watt	43	Obsolete	$0.00	$0.00	$6.19	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
71	Cobrahead DW 100/150	HPS	150-watt	62	Obsolete	$0.00	$0.00	$8.93	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
2	Victorian	QL	85-watt	32	Obsolete	$0.00	$0.00	$4.61	$0.00	$0.00	$2.24		-	-	326	326	125	$0	$0	$18,034
1	Victorian	QL	165-watt	60	Obsolete	$0.00	$0.00	$8.64	$0.00	$0.00	$4.20		-	-	219	219	158	$0	$0	$22,706
3	Techtra	QL	165-watt	60	Obsolete	$0.00	$1.07	$8.64	$0.00	$5.27	$4.20		-	117	4	121	87	$0	$1,502	$12,545
95	KIM SBC Shoebox	HPS	150-watt	62	Obsolete	$0.00	$0.94	$8.93	$0.00	$5.28	$4.34		-	28	65	93	69	$0	$316	$9,966
96	KIM Archetype	HPS	250-watt	102	Obsolete	$0.00	$1.82	$14.69	$0.00	$8.97	$7.15		-	57	20	77	94	$0	$1,245	$13,574
97	KIM Archetype	HPS	400-watt	163	Obsolete	$0.00	$2.17	$23.48	$0.00	$13.59	$11.42		-	16	28	44	86	$0	$417	$12,397
80	Acorn Type	HPS	70-watt	30	Obsolete	$0.00	$1.47	$4.32	$0.00	$3.57	$0.00		-	9	-	9	3	$0	$159	$467
73	GardCo Bronze - (C) Only	HPS	70-watt	30	Obsolete	$0.00	$0.00	$4.32	$0.00	$0.00	$2.10		-	-	5	5	2	$0	$0	$259
72	GardCo Bronze - (C) Only	MV	175-watt	66	Obsolete	$0.00	$0.00	$9.51	$0.00	$0.00	$4.62		-	-	1	1	1	$0	$0	$114
25	Post-Top - Black	HPS	70-watt	30	Obsolete	$0.00	$1.06	$4.32	$0.00	$3.16	$2.10		-	332	4	336	121	$0	$4,223	$17,418
43	Rect.Type - (C) Only	HPS	200-watt	79	Obsolete	$0.00	$0.00	$11.38	$0.00	$0.00	$5.53		-	-	16	16	15	$0	$0	$2,185
5	Incand. - (C) Only	IND	92-watt	31	Obsolete	$0.00	$0.00	$4.47	$0.00	$0.00	$2.17		-	-	16	16	6	$0	$0	$858
6	Incand. - (C) Only	IND	182-watt	62	Obsolete	$0.00	$0.00	$8.93	$0.00	$0.00	$4.34		-	-	4	4	3	$0	$0	$429
29	Town and Country Post-Top	MV	175-watt	66	Obsolete	$0.00	$1.10	$9.51	$0.00	$5.72	$4.62		-	190	7	197	156	$0	$2,508	$22,482
27	Flood	HPS	70-watt	30	Obsolete	$0.00	$0.00	$4.32	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
30	Flood	HPS	100-watt	43	Obsolete	$0.00	$1.08	$6.19	$0.00	$4.09	$0.00		-	-	-	0	0	$0	$0	$0
38	Flood	HPS	200-watt	79	Obsolete	$0.00	$1.16	$11.38	$0.00	$6.69	$5.53		-	3	3	6	6	$0	$42	$819
41	Cobrahead - PD	HPS	310-watt	124	Obsolete	$0.00	$0.00	$17.86	$0.00	$0.00	$0.00		-	-	-	0	0	$0	$0	$0
14	Ornamental - (C) Only	HPS	100-watt	43	Obsolete	$0.00	$0.00	$6.19	$0.00	$0.00	$3.01		-	-	80	80	41	$0	$0	$5,942
15	Twin Ornamental -(C) Only	HPS	Twin 100-watt	86	Obsolete	$0.00	$0.00	$12.39	$0.00	$0.00	$6.03		-	-	2	2	2	$0	$0	$297
7	Flourescent - (C) Only	FLR	28-watt	12	Obsolete	$0.00	$0.00	$1.73	$0.00	$0.00	$0.84		-	-	9	9	1	$0	$0	$187
100	Cobrahead	LED	>30W-35W	11	Standard	$5.62	$0.39	$1.58	$6.39	$1.16	$0.00		1,649	470	-	2,119	280	$111,209	$2,200	$40,176
101	Cobrahead	LED	>45W-50W	16	Standard	$5.51	$0.39	$2.30	$6.63	$1.51	$0.00		23,726	1	-	23,727	4,556	$1,568,763	$5	$654,865
102	Cobrahead	LED	>50W-55W	18	Standard	$5.79	$0.39	$2.59	$7.05	$1.65	$1.26		2,119	2,619	3	4,741	1,024	$147,228	$12,257	$147,350
103	Cobrahead	LED	>65W-70W	23	Standard	$6.27	$0.40	$3.31	$7.88	$2.01	$0.00		4,943	-	-	4,943	1,364	$371,911	$0	$196,336
104	Cobrahead	LED	>100W-110W	36	Standard	$6.11	$0.40	$5.19	$8.63	$2.92	$0.00		1,660	540	-	2,200	950	$121,711	$2,592	$137,016
105	Cobrahead	LED	>130W-140W	46	Standard	$6.69	$0.41	$6.63	$9.91	$3.63	$0.00		68	-	-	68	38	$5,459	$0	$5,410
107	Cobrahead	LED	>170W-180W	60	Standard	$8.33	$0.44	$8.64	$12.53	$4.64	$0.00		171	-	-	171	123	$17,093	$0	$17,729
108	Cobrahead	LED	>190W-200W	67	Standard	$7.83	$0.43	$9.65	$12.52	$5.12	$0.00		157	380	-	537	432	$14,752	$1,961	$62,185
109	Cobrahead	LED	>20W-25W	8	Standard	$5.35	$0.39	$1.15	$5.91	$0.95	$0.00		-	-	-	0	0	$0	$0	$0
132	Cobrahead	LED	>150W-160W	53	Standard	$8.67	$0.45	$7.63	$12.38	$4.16	$0.00		820	1,063	-	1,883	1,198	$85,313	$5,740	$172,407
133	Cobrahead	LED	>25W-30W	9	Standard	$5.35	$0.39	$1.30	$5.98	$1.02	$0.00		5,170	371	-	5,541	598	$331,914	$1,736	$86,440
134	Cobrahead	LED	>40W-45W	15	Standard	$5.52	$0.39	$2.16	$6.57	$1.44	$0.00		1,990	423	-	2,413	434	$131,818	$1,980	$62,545
135	Cobrahead	LED	>85W-90W	30	Standard	$6.30	$0.40	$4.32	$8.40	$2.50	$0.00		1,812	873	-	2,685	967	$136,987	$4,190	$139,190
200	Cobrahead	LED	>35W-40W	13	Standard	$5.35	$0.39	$1.87	$6.26	$1.30	$0.91		-	-	-	0	0	$0	$0	$0
201	Cobrahead	LED	>55W-60W	20	Standard	$5.52	$0.39	$2.88	$6.92	$1.79	$1.40		-	-	-	0	0	$0	$0	$0
202	Cobrahead	LED	>60W-65W	21	Standard	$5.52	$0.39	$3.02	$6.99	$1.86	$1.47		-	-	-	0	0	$0	$0	$0
203	Cobrahead	LED	>70W-75W	25	Standard	$6.30	$0.40	$3.60	$8.05	$2.15	$1.75		-	-	-	0	0	$0	$0	$0
204	Cobrahead	LED	>75W-80W	26	Standard	$6.30	$0.40	$3.75	$8.12	$2.22	$1.82		-	-	-	0	0	$0	$0	$0
205	Cobrahead	LED	>80W-85W	28	Standard	$6.30	$0.40	$4.03	$8.26	$2.36	$1.96		-	-	-	0	0	$0	$0	$0
206	Cobrahead	LED	>90W-95W	32	Standard	$6.30	$0.40	$4.61	$8.54	$2.64	$2.24		-	-	-	0	0	$0	$0	$0
207	Cobrahead	LED	>95W-100W	33	Standard	$6.30	$0.40	$4.75	$8.61	$2.71	$2.31		-	-	-	0	0	$0	$0	$0
208	Cobrahead	LED	>110W-120W	39	Standard	$6.30	$0.40	$5.62	$9.03	$3.13	$2.73		-	-	-	0	0	$0	$0	$0
209	Cobrahead	LED	>120W-130W	43	Standard	$6.30	$0.40	$6.19	$9.31	$3.41	$3.01		-	-	-	0	0	$0	$0	$0
210	Cobrahead	LED	>140W-150W	50	Standard	$8.67	$0.45	$7.20	$12.17	$3.95	$3.50		-	-	-	0	0	$0	$0	$0
211	Cobrahead	LED	>160W-170W	56	Standard	$8.67	$0.45	$8.07	$12.59	$4.37	$3.92		-	-	-	0	0	$0	$0	$0
212	Cobrahead	LED	>180W-190W	63	Standard	$8.67	$0.45	$9.07	$13.08	$4.86	$4.41		-	-	-	0	0	$0	$0	$0
110	Acorn	LED	>45W-50W	16	Custom	$11.11	$0.49	$2.30	$12.23	$1.61	$0.00		216	104	-	320	61	$28,797	$612	$8,832
111	Acorn	LED	>65W-70W	23	Custom	$13.35	$0.53	$3.31	$14.96	$2.14	$0.00		636	139	-	775	214	$101,887	$884	$30,783
137	Acorn	LED	>35W-40W	13	Custom	$13.72	$0.53	$1.87	$14.63	$1.44	$0.00		11	-	-	11	2	$1,811	$0	$247
138	Acorn	LED	>55W-60W	20	Custom	$13.72	$0.53	$2.88	$15.12	$1.93	$0.00		1,973	45	-	2,018	484	$324,835	$286	$69,742
139	Acorn	LED	>70W-75W	25	Custom	$13.72	$0.53	$3.60	$15.47	$2.28	$0.00		119	94	-	213	64	$19,592	$598	$9,202
213	Acorn	LED	>40W-45W	15	Custom	$13.72	$0.53	$2.16	$14.77	$1.58	$1.05		-	14	-	14	3	$0	$89	$363
214	Acorn	LED	>50W-55W	18	Custom	$13.72	$0.53	$2.59	$14.98	$1.79	$1.26		-	-	-	0	0	$0	$0	$0

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum				Monthly		Tariff Rates		Monthly	DAX Sch 91 & 95 A & B RATES				Proposed Sch 91 & 95 A & B Counts				Annual	Annual Fixed Revenue		Annual
CODE	Light Description	Type	Watts	kWh	Category	A	B	Energy	A	B	C	TOTAL	A	B	C	TOTAL	MWh	A	B	Energy
215	Acorn	LED	>60W-65W	21	Custom	$13.72	$0.53	$3.02	$15.19	$2.00	$1.47		-	-	-	0	0	$0	$0	$0
112	Pendant (non-flared)	LED	53	18	Custom	$15.46	$0.56	$2.59	$16.72	$1.82	$0.00		62	-	-	62	13	$11,502	$0	$1,927
113	Pendant (non-flared)	LED	69	24	Custom	$15.23	$0.56	$3.46	$16.91	$2.24	$0.00		-	-	-	0	0	$0	$0	$0
114	Pendant (non-flared)	LED	85	29	Custom	$15.79	$0.57	$4.18	$17.82	$2.60	$0.00		2	-	-	2	1	$379	$0	$100
117	Pendant (flared)	LED	>50W-55W	18	Custom	$17.37	$0.60	$2.59	$18.63	$1.86	$0.00		1,119	4	-	1,123	243	$233,244	$29	$34,903
118	Pendant (flared)	LED	>65W-70W	23	Custom	$16.48	$0.58	$3.31	$18.09	$2.19	$0.00		56	2	-	58	16	$11,075	$14	$2,304
119	Pendant (flared)	LED	>80W-85W	28	Custom	$16.70	$0.59	$4.03	$18.66	$2.55	$0.00		9	5	-	14	5	$1,804	$35	$677
127	Pendant (non-flare)	LED	36	12	Custom	$14.32	$0.54	$1.73	$15.16	$1.38	$0.00		7	4	-	11	2	$1,203	$26	$228
128	Pendant (flare)	LED	>35W-40W	13	Custom	$13.74	$0.53	$1.87	$14.65	$1.44	$0.00		1,125	142	-	1,267	198	$185,490	$903	$28,431
216	Pendant (flare)	LED	>40W-45W	15	Standard	$14.60	$0.55	$2.16	$15.65	$1.60	$1.05		-	-	-	0	0	$0	$0	$0
217	Pendant (flare)	LED	>45W-50W	16	Standard	$14.60	$0.55	$2.30	$15.72	$1.67	$1.12		-	-	-	0	0	$0	$0	$0
218	Pendant (flare)	LED	>55W-60W	20	Standard	$13.74	$0.53	$2.88	$15.14	$1.93	$1.40		13	-	200	213	51	$2,143	$0	$7,361
219	Pendant (flare)	LED	>60W-65W	21	Standard	$17.37	$0.60	$3.02	$18.84	$2.07	$1.47		-	-	-	0	0	$0	$0	$0
220	Pendant (flare)	LED	>70W-75W	25	Standard	$13.74	$0.53	$3.60	$15.49	$2.28	$1.75		24	-	51	75	23	$3,957	$0	$3,240
221	Pendant (flare)	LED	>75W-80W	26	Standard	$16.70	$0.59	$3.75	$18.52	$2.41	$1.82		-	-	-	0	0	$0	$0	$0
222	CREE XSP	LED	>30W-35W	11	Standard	$5.51	$0.39	$1.58	$6.28	$1.16	$0.77		-	-	-	0	0	$0	$0	$0
223	CREE XSP	LED	>65W-70W	23	Standard	$6.12	$0.40	$3.31	$7.73	$2.01	$1.61		-	-	-	0	0	$0	$0	$0
224	CREE XSP	LED	>130W-140W	46	Standard	$7.63	$0.43	$6.63	$10.85	$3.65	$3.22		-	-	-	0	0	$0	$0	$0
225	Cobrahead	LED	>200W-210W	70	Standard	$7.90	$0.43	$10.08	$12.80	$5.33	$4.90		-	-	-	0	0	$0	$0	$0
226	Cobrahead	LED	>210W-220W	74	Standard	$8.69	$0.45	$10.66	$13.87	$5.63	$5.18		-	-	-	0	0	$0	$0	$0
227	Cobrahead	LED	>220W-230W	77	Standard	$8.69	$0.45	$11.09	$14.08	$5.84	$5.39		-	-	-	0	0	$0	$0	$0
228	Cobrahead	LED	>230W-240W	81	Standard	$8.69	$0.45	$11.67	$14.36	$6.12	$5.67		-	-	-	0	0	$0	$0	$0
229	Cobrahead	LED	>240W-250W	84	Standard	$9.19	$0.46	$12.10	$15.08	$6.35	$5.89		-	-	-	0	0	$0	$0	$0
230	Flood	LED	321-330W	112	Standard	$13.62	$0.56	$16.13	$21.47	$8.41	$7.85		-	-	-	0	0	$0	$0	$0
231	Acorn	LED	91-100W	32	Standard	$13.76	$0.57	$4.61	$16.00	$2.81	$2.24		-	-	-	0	0	$0	$0	$0
232	Flood	LED	331-340W	116	Standard	$13.62	$0.56	$16.71	$21.75	$8.69	$8.13		-	-	-	0	0	$0	$0	$0
233	Flood	LED	341-350W	119	Standard	$13.62	$0.56	$17.14	$21.96	$8.90	$8.34		-	-	-	0	0	$0	$0	$0
234	Flood	LED	351-360W	123	Standard	$13.62	$0.56	$17.72	$22.24	$9.18	$8.62		-	-	-	0	0	$0	$0	$0
129	Post-Top, American Revolution	LED	>30W-35W	11	Custom	$7.14	$0.42	$1.58	$7.91	$1.19	$0.00		8,586	530	-	9,116	1,203	$735,648	$2,671	$172,839
130	Post-Top, American Revolution	LED	>45W-50W	16	Custom	$7.14	$0.42	$2.30	$8.26	$1.54	$0.00		101	1	-	102	20	$8,654	$5	$2,815
131	HADCO Acorn	LED	70	24	Custom	$17.31	$0.60	$3.46	$18.99	$2.28	$0.00		259	-	-	259	75	$53,799	$0	$10,754
141	Flood	LED	>120W-130W	43	Standard	$7.96	$0.43	$6.19	$10.97	$3.44	$0.00		58	1	-	59	30	$5,540	$5	$4,383
142	Flood	LED	>180W-190W	63	Standard	$9.17	$0.45	$9.07	$13.58	$4.86	$0.00		112	2	-	114	86	$12,324	$11	$12,408
143	Flood	LED	>370W-380W	127	Standard	$13.62	$0.56	$18.29	$22.52	$9.46	$8.90		9	-	50	59	90	$1,471	$0	$12,949
144	Flood	LED	>80W-85W	28	Standard	$7.41	$0.42	$4.03	$9.37	$2.38	$0.00		5	-	-	5	2	$445	$0	$242
145	5 - 10	LED		3		$0.00	$0.00	$0.43	$0.00	$0.00	$0.21		-	-	4	4	0	$0	$0	$21
146	>10 - 15	LED		4		$0.00	$0.00	$0.58	$0.00	$0.00	$0.28		-	-	-	0	0	$0	$0	$0
147	>15 - 20	LED		6		$0.00	$0.00	$0.86	$0.00	$0.00	$0.42		-	-	21	21	2	$0	$0	$217
148	>20 - 25	LED		8		$0.00	$0.00	$1.15	$0.00	$0.00	$0.56		-	-	823	823	79	$0	$0	$11,357
149	>25 - 30	LED		9		$0.00	$0.00	$1.30	$0.00	$0.00	$0.63		-	-	27,819	27,819	3,004	$0	$0	$433,976
150	>30 - 35	LED		11		$0.00	$0.00	$1.58	$0.00	$0.00	$0.77		-	-	4,132	4,132	545	$0	$0	$78,343
151	>35 - 40	LED		13		$0.00	$0.00	$1.87	$0.00	$0.00	$0.91		-	-	4,574	4,574	714	$0	$0	$102,641
152	>40 - 45	LED		15		$0.00	$0.00	$2.16	$0.00	$0.00	$1.05		-	-	6,086	6,086	1,095	$0	$0	$157,749
153	>45 - 50	LED		16		$0.00	$0.00	$2.30	$0.00	$0.00	$1.12		-	-	2,012	2,012	386	$0	$0	$55,531
154	>50 - 55	LED		18		$0.00	$0.00	$2.59	$0.00	$0.00	$1.26		-	-	2,825	2,825	610	$0	$0	$87,801
155	>55 - 60	LED		20		$0.00	$0.00	$2.88	$0.00	$0.00	$1.40		-	-	2,551	2,551	612	$0	$0	$88,163
156	>60 - 65	LED		21		$0.00	$0.00	$3.02	$0.00	$0.00	$1.47		-	-	6,614	6,614	1,667	$0	$0	$239,691
157	>65 - 70	LED		23		$0.00	$0.00	$3.31	$0.00	$0.00	$1.61		-	-	1,204	1,204	332	$0	$0	$47,823
158	>70 - 75	LED		25		$0.00	$0.00	$3.60	$0.00	$0.00	$1.75		-	-	174	174	52	$0	$0	$7,517
159	>75 - 80	LED		26		$0.00	$0.00	$3.75	$0.00	$0.00	$1.82		-	-	212	212	66	$0	$0	$9,540
160	>80 - 85	LED		28		$0.00	$0.00	$4.03	$0.00	$0.00	$1.96		-	-	1,674	1,674	562	$0	$0	$80,955
161	>85 - 90	LED		30		$0.00	$0.00	$4.32	$0.00	$0.00	$2.10		-	-	3,763	3,763	1,355	$0	$0	$195,074
162	>90 - 95	LED		32		$0.00	$0.00	$4.61	$0.00	$0.00	$2.24		-	-	230	230	88	$0	$0	$12,724
163	>95 - 100	LED		33		$0.00	$0.00	$4.75	$0.00	$0.00	$2.31		-	-	193	193	76	$0	$0	$11,001
164	>100 - 110	LED		36		$0.00	$0.00	$5.19	$0.00	$0.00	$2.52		-	-	880	880	380	$0	$0	$54,806
165	>110 - 120	LED		39		$0.00	$0.00	$5.62	$0.00	$0.00	$2.73		-	-	149	149	70	$0	$0	$10,049
166	>120 - 130	LED		43		$0.00	$0.00	$6.19	$0.00	$0.00	$3.01		-	-	264	264	136	$0	$0	$19,610
167	>130 - 140	LED		46		$0.00	$0.00	$6.63	$0.00	$0.00	$3.22		-	-	2,537	2,537	1,400	$0	$0	$201,844
168	>140 - 150	LED		50		$0.00	$0.00	$7.20	$0.00	$0.00	$3.50		-	-	194	194	116	$0	$0	$16,762
169	>150 - 160	LED		53		$0.00	$0.00	$7.63	$0.00	$0.00	$3.71		-	-	639	639	406	$0	$0	$58,507

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	DAX Sch 91 & 95 A & B RATES A	B	C	TOTAL	Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	Annual Fixed Revenue B	Annual Energy
170	>160 - 170	LED		56		$0.00	$0.00	$8.07	$0.00	$0.00	$3.92		-	-	161	161	108	$0	$0	$15,591
171	>170 - 180	LED		60		$0.00	$0.00	$8.64	$0.00	$0.00	$4.20		-	-	92	92	66	$0	$0	$9,539
172	>180 - 190	LED		63		$0.00	$0.00	$9.07	$0.00	$0.00	$4.41		-	-	1,102	1,102	833	$0	$0	$119,942
173	>190 - 200	LED		67		$0.00	$0.00	$9.65	$0.00	$0.00	$4.69		-	-	64	64	51	$0	$0	$7,411
174	>200 - 210	LED		70		$0.00	$0.00	$10.08	$0.00	$0.00	$4.90		-	-	25	25	21	$0	$0	$3,024
175	>210 - 220	LED		75		$0.00	$0.00	$10.80	$0.00	$0.00	$5.25		-	-	-	0	0	$0	$0	$0
176	>220 - 230	LED		77		$0.00	$0.00	$11.09	$0.00	$0.00	$5.39		-	-	90	90	83	$0	$0	$11,977
177	>230 - 240	LED		80		$0.00	$0.00	$11.52	$0.00	$0.00	$5.60		-	-	-	0	0	$0	$0	$0
178	>240 - 250	LED		84		$0.00	$0.00	$12.10	$0.00	$0.00	$5.89		-	-	290	290	292	$0	$0	$42,108
179	>250 - 260	LED		87		$0.00	$0.00	$12.53	$0.00	$0.00	$6.10		-	-	14	14	15	$0	$0	$2,105
180	>260 - 270	LED		91		$0.00	$0.00	$13.11	$0.00	$0.00	$6.38		-	-	-	0	0	$0	$0	$0
181	>270 - 280	LED		94		$0.00	$0.00	$13.54	$0.00	$0.00	$6.59		-	-	18	18	20	$0	$0	$2,925
182	>280 - 290	LED		97		$0.00	$0.00	$13.97	$0.00	$0.00	$6.80		-	-	-	0	0	$0	$0	$0
183	>290 - 300	LED		101		$0.00	$0.00	$14.55	$0.00	$0.00	$7.08		-	-	-	0	0	$0	$0	$0
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								Totals					58,831	15,359	76,982	151,172	39,188	$4,792,628	$162,067	$5,642,237
																		$291,143	-$291,342	

Notes:
1. Obsolete fixtures are not available to new service
2. Option C are customer owned and maintained and only pay the respective energy charge

PORTLAND GENERAL ELECTRIC
Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
57	Fiberglass, 2-Piece, Color may vary	Fiberglass	20	A	$5.69	5,910	$403,535
59	Fiberglass, 2-Piece, Black or Bronze	Fiberglass	30	A	$9.26	2,854	$317,136
61	Fiberglass, 2-Piece, Gray	Fiberglass	30	A	$9.26	6,487	$720,835
1	Wood, SLO	Wood	30 to 35	A	$6.92	1,387	$115,176
3	Wood, SLO	Wood	40 to 55	A	$8.10	216	$20,995
58	Fiberglass, 2-Piece, Color may vary	Fiberglass	20	B	$0.19	4,510	$10,283
60	Fiberglass, 2-Piece, Black or Bronze	Fiberglass	30	B	$0.31	4,358	$16,212
62	Fiberglass, 2-Piece, Gray	Fiberglass	30	B	$0.31	6,587	$24,504
46	Wood, SLO	Wood	30 to 35	B	$0.23	149	$411
47	Wood, SLO	Wood	40 to 55	B	$0.27	38	$123
31	Aluminum, Regular, Post-Top	Aluminum	16	A	$5.28	540	$34,214
32	Aluminum, Regular with 4' Arm	Aluminum	25	A	$9.77	3,574	$419,016
33	Aluminum, Regular with 6' Arm	Aluminum	30	A	$11.16	357	$47,809
28	Aluminum, Regular with 8' Arm	Aluminum	35	A	$12.87	172	$26,564
18	Aluminum with 4' Davit Arm	Aluminum	25	A	$10.40	75	$9,360
6	Aluminum with 6' Davit Arm	Aluminum	30	A	$11.67	659	$92,286
29	Aluminum with 8' Davit Arm	Aluminum	35	A	$13.29	720	$114,826
70	Aluminum with 8' Davit Arm	Aluminum	40	A	$17.04	99	$20,244
27	Aluminum with 2-6' Double Davit	Aluminum	30	A	$12.91	62	$9,605
65	Aluminum, Fluted Ornamental, Post-Top	Aluminum	14	A	$9.14	194	$21,278
69	Aluminum, Smooth Techtra Ornamental	Aluminum	18	A	$19.46	559	$130,538
66	Aluminum, Ornamental, Post-Top	Aluminum	16	A	$9.48	714	$81,225
79	Aluminum, Fluted Ornamental, Pendant	Aluminum	18	A	$18.32	96	$21,105
81	Aluminum, Non-Fluted Ornamental, Pendant	Aluminum	18	A	$18.21	1,793	$391,806
85	Fiberglass, 1-Piece, Anchor Base, Color May Va	Fiberglass	25	A	$10.89	2	$261
63	Fiberglass, Ornamental Black	Fiberglass	14	A	$12.05	674	$97,460
83	Fiberglass, 2-Piece, Black or Bronze	Fiberglass	18	A	$6.09	9	$658
67	Fiberglass, Color may vary	Fiberglass	22	A	$5.13	70	$4,309
68	Fiberglass, 2-Piece, Color may vary	Fiberglass	35	A	$8.98	575	$61,962
16	Fiberglass, Anchor Base, Gray or Black	Fiberglass	35	A	$12.15	55	$8,019
35	Fiberglass, Direct Bury with Shroud	Fiberglass	18	A	$7.78	6	$560
34	Aluminum, Regular, Post-Top	Aluminum	16	B	$0.17	52	$106
8	Aluminum, Regular with 4' Arm	Aluminum	25	B	$0.32	745	$2,861
48	Aluminum, Regular with 6' Arm	Aluminum	30	B	$0.37	501	$2,224
54	Aluminum, Regular with 8' Arm	Aluminum	35	B	$0.42	386	$1,945
13	Aluminum with 4' Davit Arm	Aluminum	25	B	$0.34	119	$486
12	Aluminum with 6' Davit Arm	Aluminum	30	B	$0.38	734	$3,347
53	Aluminum with 8' Davit Arm	Aluminum	35	B	$0.44	1,070	$5,650
76	Aluminum with 8' Davit Arm	Aluminum	40	B	$0.56	219	$1,472
14	Aluminum with 2-6' Double Davit	Aluminum	30	B	$0.43	53	$273
71	Aluminum, Fluted Ornamental, Post-Top	Aluminum	14	B	$0.30	1,087	$3,913
75	Aluminum, Smooth Techtra Ornamental	Aluminum	18	B	$0.64	422	$3,241
72	Aluminum, Ornamental, Post-Top	Aluminum	16	B	$0.31	1,129	$4,200
80	Aluminum, Fluted Ornamental, Pendant	Aluminum	18	B	$0.60	431	$3,103
82	Aluminum, Non-Fluted Ornamental, Pendant	Aluminum	18	B	$0.60	272	$1,958
44	Aluminum, Painted Ornamental	Aluminum	35	B	$0.44	60	$317
91	Aluminum, Regular with Breakaway Base, 8' Arn	Aluminum	35	A	$18.28	0	$0
92	Aluminum, Regular with Breakaway Base, 8' Arn	Aluminum	35	B	$0.60	69	$497
93	Aluminum, Double-Arm, Smooth	Aluminum	25	A	$15.40	4	$739

PORTLAND GENERAL ELECTRIC
Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
86	Fiberglass, 1-Piece, Anchor Base, Color May Va	Fiberglass	30	A	$13.24	0	$0
94	Aluminum, Double-Arm, Smooth	Aluminum	25	B	$0.51	0	$0
95	Aluminum, Smooth, Black, Pendant	Aluminum	23	A	$18.65	0	$0
96	Aluminum, Smooth, Black, Pendant	Aluminum	23	B	$0.61	0	$0
97	Aluminum, Regular with Breakaway Base	Aluminum	25	A	$16.56	0	$0
98	Aluminum, Regular with Breakaway Base	Aluminum	25	B	$0.55	0	$0
99	Aluminum, Regular with Breakaway Base	Aluminum	30	A	$16.90	0	$0
100	Aluminum, Regular with Breakaway Base	Aluminum	30	B	$0.56	0	$0
88	Fiberglass, 1-Piece, Anchor Base, Color May Va	Fiberglass	25	B	$0.36	15	$65
89	Fiberglass, 1-Piece, Anchor Base, Color May Va	Fiberglass	30	B	$0.44	0	$0
64	Fiberglass, Ornamental Black	Fiberglass	14	B	$0.40	1,438	$6,902
84	Fiberglass, 2-Piece, Black or Bronze	Fiberglass	18	B	$0.20	1	$2
73	Fiberglass, Color may vary	Fiberglass	22	B	$0.17	365	$745
74	Fiberglass, 2-Piece, Color may vary	Fiberglass	35	B	$0.30	1,592	$5,731
17	Fiberglass, Anchor Base, Gray or Black	Fiberglass	35	B	$0.40	81	$389
36	Fiberglass, Direct Bury with Shroud	Fiberglass	18	B	$0.26	352	$1,098
2	Aluminum Post	Aluminum	30	A	$5.23	343	$21,527
30	Concrete, Ornamental Post	Concrete	35 or less	A	$9.66	57	$6,607
37	Steel, Painted Regular	Steel	25	A	$9.66	291	$33,733
38	Steel, Painted Regular	Steel	30	A	$11.01	126	$16,647
39	Wood, Laminated without Mast Arm	Wood	20	A	$0.00	0	$0
24	Wood, Laminated SLO Pole	Wood	20	A	$0.00	0	$0
41	Wood, Curved laminated	Wood	30	A	$0.00	0	$0
11	Wood, Painted Underground	Wood	35	A	$6.85	9	$740
55	Bronze Alloy GardCo	Bronze	12	B	$0.00	0	$0
25	Concrete, Ornamental Post	Concrete	35 or less	B	$0.32	6	$23
7	Steel, Painted Regular	Steel	25	B	$0.32	90	$346
49	Steel, Painted Regular	Steel	30	B	$0.36	0	$0
21	Steel, Unpainted 6-foot Mast Arm	Steel	30	B	$0.36	9	$39
51	Steel, Unpainted 6-foot Davit Arm	Steel	30	B	$0.00	0	$0
40	Steel, Unpainted 8-foot Mast Arm	Steel	35	B	$0.44	187	$987
42	Steel, Unpainted 8-foot Davit Arm	Steel	35	B	$0.00	0	$0
23	Wood, Laminated without Mast Arm	Wood	20	B	$0.19	447	$1,019
45	Wood, Curved laminated	Wood	30	B	$0.26	66	$206
26	Wood, Painted Underground	Wood	35	B	$0.23	211	$582
				Total Option As		28,689	$3,250,776
				Total Option Bs		27,851	$105,261
						56,540	$3,356,037

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

					Monthly Tariff Price			DAX Monthly Tariff Price				Annual	Revenues		
Code	**Description**	**Type**	**Size**	**kWh**	**Fixed**	**Energy**	**Total**	**Fixed**	**Energy**	**Total**	**Count**	**MWh**	**Fixed**	**Energy**	**Total**
Fixtures															
3	Techtra	QL	165-watt	60	$22.66	$8.64	$31.30	$22.66	$4.20	$26.86	0	0	$0	$0	$0
21	Cobrahead	MV	175-watt	66	$5.17	$9.51	$14.68	$5.17	$4.62	$9.79	117	93	$7,259	$13,352	$20,611
23	Cobrahead	MV	400-watt	147	$5.82	$21.17	$26.99	$5.82	$10.30	$16.12	191	337	$13,339	$48,522	$61,861
24	Cobrahead	MV	1000-watt	374	$5.70	$53.87	$59.57	$5.70	$26.20	$31.90	18	81	$1,231	$11,636	$12,867
33	Cobrahead - (non-pd)	HPS	70-watt	30	$6.08	$4.32	$10.40	$6.08	$2.10	$8.18	58	21	$4,232	$3,007	$7,238
34	Cobrahead - (non-pd)	HPS	100-watt	43	$5.26	$6.19	$11.45	$5.26	$3.01	$8.27	41	21	$2,588	$3,045	$5,633
35	Cobrahead - (non-pd)	HPS	150-watt	62	$5.34	$8.93	$14.27	$5.34	$4.34	$9.68	9	7	$577	$964	$1,541
39	Cobrahead - (non-pd)	HPS	200-watt	79	$5.85	$11.38	$17.23	$5.85	$5.53	$11.38	15	14	$1,053	$2,048	$3,101
36	Cobrahead - (non-pd)	HPS	250-watt	102	$5.50	$14.69	$20.19	$5.50	$7.15	$12.65	11	13	$726	$1,939	$2,665
41	Cobrahead - (PD)	HPS	310-watt	124	$5.61	$17.86	$23.47	$5.61	$8.69	$14.30	6	9	$404	$1,286	$1,690
37	Cobrahead - (non-pd)	HPS	400-watt	163	$5.62	$23.48	$29.10	$5.62	$11.42	$17.04	489	956	$32,978	$137,781	$170,759
30	Flood	HPS	100-watt	43	$5.14	$6.19	$11.33	$5.14	$3.01	$8.15	214	110	$13,200	$15,896	$29,095
38	Flood	HPS	200-watt	79	$7.30	$11.38	$18.68	$7.30	$5.53	$12.83	403	382	$35,303	$55,034	$90,336
31	Flood	HPS	250-watt	102	$7.46	$14.69	$22.15	$7.46	$7.15	$14.61	455	557	$40,732	$80,207	$120,939
32	Flood	HPS	400-watt	163	$7.36	$23.48	$30.84	$7.36	$11.42	$18.78	1,004	1,964	$88,673	$282,887	$371,560
76	Shoebox	HPS	70-watt	30	$5.88	$4.32	$10.20	$5.88	$2.10	$7.98	5	2	$353	$259	$612
77	Shoebox	HPS	100-watt	43	$6.47	$6.19	$12.66	$6.47	$3.01	$9.48	250	129	$19,410	$18,570	$37,980
78	Shoebox	HPS	150-watt	62	$6.93	$8.93	$15.86	$6.93	$4.34	$11.27	35	26	$2,911	$3,751	$6,661
81	Special Acorn	HPS	100-watt	43	$11.14	$6.19	$17.33	$11.14	$3.01	$14.15	54	28	$7,219	$4,011	$11,230
82	HADCO - Victorian	HPS	150-watt	62	$11.16	$8.93	$20.09	$11.16	$4.34	$15.50	1	1	$134	$107	$241
49	HADCO - Victorian	HPS	200-watt	79	$9.72	$11.38	$21.10	$9.72	$5.53	$15.25	0	0	$0	$0	$0
83	HADCO - Victorian	HPS	250-watt	102	$9.52	$14.69	$24.21	$9.52	$7.15	$16.67	0	0	$0	$0	$0
40	Early American Post-Top	HPS	100-watt	43	$6.78	$6.19	$12.97	$6.78	$3.01	$9.79	59	30	$4,800	$4,383	$9,183
62	Cobrahead	MH	150-watt	60	$7.68	$8.64	$16.32	$7.68	$4.20	$11.88	2	1	$184	$207	$392
48	Cobrahead	MH	175-watt	71	$5.95	$10.23	$16.18	$5.95	$4.97	$10.92	1	1	$71	$123	$194
61	Flood	MH	350-watt	139	$8.57	$20.02	$28.59	$8.57	$9.74	$18.31	199	332	$20,465	$47,808	$68,273
60	Flood	MH	400-watt	156	$6.20	$22.47	$28.67	$6.20	$10.93	$17.13	296	554	$22,022	$79,813	$101,836
47	Flood	HPS	750-watt	285	$10.75	$41.05	$51.80	$10.75	$19.97	$30.72	31	106	$3,999	$15,271	$19,270
12	Special Acorn - Independence	HPS	100-watt	43	$10.80	$6.19	$16.99	$10.80	$3.01	$13.81	0	0	$0	$0	$0
64	HADCO Capitol Acorn	HPS	100-watt	43	$13.76	$6.19	$19.95	$13.76	$3.01	$16.77	0	0	$0	$0	$0
65	HADCO Capitol Acorn	HPS	200-watt	79	$14.04	$11.38	$25.42	$14.04	$5.53	$19.57	0	0	$0	$0	$0
66	HADCO Capitol Acorn	HPS	250-watt	102	$12.73	$14.69	$27.42	$12.73	$7.15	$19.88	0	0	$0	$0	$0
98	HADCO Techtra	HPS	100-watt	43	$17.93	$6.19	$24.12	$17.93	$3.01	$20.94	7	4	$1,506	$520	$2,026
99	HADCO Techtra	HPS	150-watt	62	$18.77	$8.93	$27.70	$18.77	$4.34	$23.11	2	1	$450	$214	$665
90	HADCO Westbrooke	HPS	70-watt	30	$12.22	$4.32	$16.54	$12.22	$2.10	$14.32	0	0	$0	$0	$0
91	HADCO Westbrooke	HPS	100-watt	43	$12.12	$6.19	$18.31	$12.12	$3.01	$15.13	0	0	$0	$0	$0
94	HADCO Westbrooke	HPS	250-watt	102	$11.69	$14.69	$26.38	$11.69	$7.15	$18.84	0	0	$0	$0	$0
9	Holophane Mongoose	HPS	150-watt	62	$11.03	$8.93	$19.96	$11.03	$4.34	$15.37	0	0	$0	$0	$0
100	Cobrahead	LED	>30W-35W	11	$5.54	$1.58	$7.12	$5.54	$0.77	$6.31	136	18	$9,041	$2,579	$11,620
101	Cobrahead	LED	>45W-50W	16	$5.43	$2.30	$7.73	$5.43	$1.12	$6.55	421	81	$27,432	$11,620	$39,052
102	Cobrahead	LED	>50W-55W	18	$5.71	$2.59	$8.30	$5.71	$1.26	$6.97	98	21	$6,715	$3,046	$9,761
103	Cobrahead	LED	>65W-70W	23	$6.19	$3.31	$9.50	$6.19	$1.61	$7.80	230	63	$17,084	$9,136	$26,220
104	Cobrahead	LED	>100W-110W	36	$6.02	$5.19	$11.21	$6.02	$2.52	$8.54	207	89	$14,954	$12,892	$27,846
105	Cobrahead	LED	>130W-140W	46	$6.61	$6.63	$13.24	$6.61	$3.22	$9.83	130	72	$10,312	$10,343	$20,654
107	Cobrahead	LED	>170W-180W	60	$8.25	$8.64	$16.89	$8.25	$4.20	$12.45	63	45	$6,237	$6,532	$12,769
108	Cobrahead	LED	>190W-200W	67	$7.75	$9.65	$17.40	$7.75	$4.69	$12.44	302	243	$28,086	$34,972	$63,058

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

					Monthly Tariff Price			DAX Monthly Tariff Price				Annual	Revenues		
Code	Description	Type	Size	kWh	Fixed	Energy	Total	Fixed	Energy	Total	Count	MWh	Fixed	Energy	Total
109	Cobrahead	LED	>20W-25W	8	$5.27	$1.15	$6.42	$5.27	$0.56	$5.83	0	0	$0	$0	$0
110	Acorn	LED	>45W-50W	16	$11.03	$2.30	$13.33	$11.03	$1.12	$12.15	15	3	$1,985	$414	$2,399
111	Acorn	LED	>65W-70W	23	$13.27	$3.31	$16.58	$13.27	$1.61	$14.88	111	31	$17,676	$4,409	$22,085
112	Pendant (non-flare)	LED	53	18	$15.38	$2.59	$17.97	$15.38	$1.26	$16.64	0	0	$0	$0	$0
113	Pendant (non-flare)	LED	69	24	$15.15	$3.46	$18.61	$15.15	$1.68	$16.83	0	0	$0	$0	$0
114	Pendant (non-flare)	LED	85	29	$15.71	$4.18	$19.89	$15.71	$2.03	$17.74	0	0	$0	$0	$0
117	Pendant (flare)	LED	>50W-55W	18	$17.29	$2.59	$19.88	$17.29	$1.26	$18.55	0	0	$0	$0	$0
118	Pendant (flare)	LED	>65W-70W	23	$16.40	$3.31	$19.71	$16.40	$1.61	$18.01	0	0	$0	$0	$0
119	Pendant (flare)	LED	>80W-85W	28	$16.62	$4.03	$20.65	$16.62	$1.96	$18.58	0	0	$0	$0	$0
122	CREE XSP	LED	>20W-25W	8	$5.43	$1.15	$6.58	$5.43	$0.56	$5.99	932	89	$60,729	$12,862	$73,591
123	CREE XSP	LED	>40W-45W	15	$5.43	$2.16	$7.59	$5.43	$1.05	$6.48	5,519	993	$359,618	$143,052	$502,671
124	CREE XSP	LED	>45W-50W	16	$5.49	$2.30	$7.79	$5.49	$1.12	$6.61	967	186	$63,706	$26,689	$90,395
125	CREE XSP	LED	>55W-60W	20	$5.49	$2.88	$8.37	$5.49	$1.40	$6.89	2,022	485	$133,209	$69,880	$203,090
126	CREE XSP	LED	>90W-95W	32	$6.04	$4.61	$10.65	$6.04	$2.24	$8.28	865	332	$62,695	$47,852	$110,547
127	Pendant (non-flare)	LED	36	12	$14.24	$1.73	$15.97	$14.24	$0.84	$15.08	0	0	$0	$0	$0
128	Pendant (flare)	LED	>35W-40W	13	$13.66	$1.87	$15.53	$13.66	$0.91	$14.57	5	1	$820	$112	$932
129	Post-Top, American Revolution	LED	>30W-35W	11	$7.05	$1.58	$8.63	$7.05	$0.77	$7.82	197	26	$16,666	$3,735	$20,401
130	Post-Top, American Revolution	LED	>45W-50W	16	$7.05	$2.30	$9.35	$7.05	$1.12	$8.17	1	0	$85	$28	$112
131	HADCO Acorn	LED	70	24	$17.23	$3.46	$20.69	$17.23	$1.68	$18.91	0	0	$0	$0	$0
132	Cobrahead	LED	>150W-160W	53	$8.59	$7.63	$16.22	$8.59	$3.71	$12.30	436	277	$44,943	$39,920	$84,863
133	Cobrahead	LED	>25W-30W	9	$5.27	$1.30	$6.57	$5.27	$0.63	$5.90	479	52	$30,292	$7,472	$37,764
134	Cobrahead	LED	>40W-45W	15	$5.44	$2.16	$7.60	$5.44	$1.05	$6.49	209	38	$13,644	$5,417	$19,061
135	Cobrahead	LED	>85W-90W	30	$6.22	$4.32	$10.54	$6.22	$2.10	$8.32	240	86	$17,914	$12,442	$30,355
137	Acorn	LED	>35W-40W	13	$13.64	$1.87	$15.51	$13.64	$0.91	$14.55	3	0	$491	$67	$558
138	Acorn	LED	>55W-60W	20	$13.64	$2.88	$16.52	$13.64	$1.40	$15.04	256	61	$41,902	$8,847	$50,749
139	Acorn	LED	>70W-75W	25	$13.64	$3.60	$17.24	$13.64	$1.75	$15.39	0	0	$0	$0	$0
141	Flood	LED	>120W-130W	43	$7.88	$6.19	$14.07	$7.88	$3.01	$10.89	718	370	$67,894	$53,333	$121,227
142	Flood	LED	>180W-190W	63	$9.09	$9.07	$18.16	$9.09	$4.41	$13.50	1,877	1,419	$204,743	$204,293	$409,036
143	Flood	LED	>370W-380W	127	$13.54	$18.29	$31.83	$13.54	$8.90	$22.44	234	357	$38,020	$51,358	$89,379
144	Flood	LED	>80W-85W	28	$7.33	$4.03	$11.36	$7.33	$1.96	$9.29	233	78	$20,495	$11,268	$31,763
200	Cobrahead	LED	>35W-40W	13	$5.27	$1.87	$7.14	$5.27	$0.91	$6.18	0	0	$0	$0	$0
201	Cobrahead	LED	>55W-60W	20	$5.44	$2.88	$8.32	$5.44	$1.40	$6.84	0	0	$0	$0	$0
202	Cobrahead	LED	>60W-65W	21	$5.44	$3.02	$8.46	$5.44	$1.47	$6.91	0	0	$0	$0	$0
203	Cobrahead	LED	>70W-75W	25	$6.22	$3.60	$9.82	$6.22	$1.75	$7.97	0	0	$0	$0	$0
204	Cobrahead	LED	>75W-80W	26	$6.22	$3.75	$9.97	$6.22	$1.82	$8.04	0	0	$0	$0	$0
205	Cobrahead	LED	>80W-85W	28	$6.22	$4.03	$10.25	$6.22	$1.96	$8.18	0	0	$0	$0	$0
206	Cobrahead	LED	>90W-95W	32	$6.22	$4.61	$10.83	$6.22	$2.24	$8.46	0	0	$0	$0	$0
207	Cobrahead	LED	>95W-100W	33	$6.22	$4.75	$10.97	$6.22	$2.31	$8.53	0	0	$0	$0	$0
208	Cobrahead	LED	>110W-120W	39	$6.22	$5.62	$11.84	$6.22	$2.73	$8.95	0	0	$0	$0	$0
209	Cobrahead	LED	>120W-130W	43	$6.22	$6.19	$12.41	$6.22	$3.01	$9.23	0	0	$0	$0	$0
210	Cobrahead	LED	>140W-150W	50	$8.59	$7.20	$15.79	$8.59	$3.50	$12.09	0	0	$0	$0	$0
211	Cobrahead	LED	>160W-170W	56	$8.59	$8.07	$16.66	$8.59	$3.92	$12.51	0	0	$0	$0	$0
212	Cobrahead	LED	>180W-190W	63	$8.59	$9.07	$17.66	$8.59	$4.41	$13.00	0	0	$0	$0	$0
213	Acorn	LED	>40W-45W	15	$13.64	$2.16	$15.80	$13.64	$1.05	$14.69	0	0	$0	$0	$0
214	Acorn	LED	>50W-55W	18	$13.64	$2.59	$16.23	$13.64	$1.26	$14.90	0	0	$0	$0	$0
215	Acorn	LED	>60W-65W	21	$13.64	$3.02	$16.66	$13.64	$1.47	$15.11	0	0	$0	$0	$0
216	Pendant (flare)	LED	>40W-45W	15	$14.52	$2.16	$16.68	$14.52	$1.05	$15.57	0	0	$0	$0	$0

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

					Monthly Tariff Price			DAX Monthly Tariff Price				Annual	Revenues		
Code	**Description**	**Type**	**Size**	**kWh**	**Fixed**	**Energy**	**Total**	**Fixed**	**Energy**	**Total**	**Count**	**MWh**	**Fixed**	**Energy**	**Total**
217	Pendant (flare)	LED	>45W-50W	16	$14.52	$2.30	$16.82	$14.52	$1.12	$15.64	0	0	$0	$0	$0
218	Pendant (flare)	LED	>55W-60W	20	$13.66	$2.88	$16.54	$13.66	$1.40	$15.06	0	0	$0	$0	$0
219	Pendant (flare)	LED	>60W-65W	21	$17.29	$3.02	$20.31	$17.29	$1.47	$18.76	0	0	$0	$0	$0
220	Pendant (flare)	LED	>70W-75W	25	$13.66	$3.60	$17.26	$13.66	$1.75	$15.41	0	0	$0	$0	$0
221	Pendant (flare)	LED	>75W-80W	26	$16.62	$3.75	$20.37	$16.62	$1.82	$18.44	0	0	$0	$0	$0
222	CREE XSP	LED	>30W-35W	11	$5.43	$1.58	$7.01	$5.43	$0.77	$6.20	80	11	$5,213	$1,517	$6,730
223	CREE XSP	LED	>65W-70W	23	$6.04	$3.31	$9.35	$6.04	$1.61	$7.65	60	17	$4,349	$2,383	$6,732
224	CREE XSP	LED	>130W-140W	46	$7.55	$6.63	$14.18	$7.55	$3.22	$10.77	64	35	$5,798	$5,092	$10,890
225	Cobrahead	LED	>200W-210W	70	$7.82	$10.08	$17.90	$7.82	$4.90	$12.72	0	0	$0	$0	$0
226	Cobrahead	LED	>210W-220W	74	$8.61	$10.66	$19.27	$8.61	$5.18	$13.79	0	0	$0	$0	$0
227	Cobrahead	LED	>220W-230W	77	$8.61	$11.09	$19.70	$8.61	$5.39	$14.00	0	0	$0	$0	$0
228	Cobrahead	LED	>230W-240W	81	$8.61	$11.67	$20.28	$8.61	$5.67	$14.28	0	0	$0	$0	$0
229	Cobrahead	LED	>240W-250W	84	$9.11	$12.10	$21.21	$9.11	$5.89	$15.00	0	0	$0	$0	$0
230	Flood	LED	321-330W	112	$13.54	$16.13	$29.67	$13.54	$7.85	$21.39	0	0	$0	$0	$0
231	Acorn	LED	91-100W	32	$13.68	$4.61	$18.29	$13.68	$2.24	$15.92	0	0	$0	$0	$0
232	Flood	LED	331-340W	116	$13.54	$16.71	$30.25	$13.54	$8.13	$21.67	0	0	$0	$0	$0
233	Flood	LED	341-350W	119	$13.54	$17.14	$30.68	$13.54	$8.34	$21.88	0	0	$0	$0	$0
234	Flood	LED	351-360W	123	$13.54	$17.72	$31.26	$13.54	$8.62	$22.16	0	0	$0	$0	$0
Totals											21,083	11,362	1,658,567	1,636,202	3,294,769
Poles															
1	Wood, SLO	Wood	30 to 35				$6.64				5,928				$472,343
3	Wood, SLO	Wood	40 to 55				$7.82				640				$60,058
11	Wood, Painted Underground	Wood	35				$6.57				1				$79
41	Wood, Curved laminated	Wood	30				$7.73				0				$0
31	Aluminum, Regular, Post-Top	Aluminum	16				$5.07				61				$3,711
32	Aluminum, Regular with 4' Arm	Aluminum	25				$9.42				42				$4,748
33	Aluminum, Regular with 6' Arm	Aluminum	30				$10.81				25				$3,243
28	Aluminum, Regular with 8' Arm	Aluminum	35				$12.52				3				$451
65	Aluminum, Fluted Ornamental, Post-Top	Aluminum	14				$8.93				34				$3,643
18	Aluminum with 4' Davit Arm	Aluminum	25				$10.05				4				$482
6	Aluminum with 6' Davit Arm	Aluminum	30				$11.32				17				$2,309
29	Aluminum with 8' Davit Arm	Aluminum	35				$12.95				1				$155
70	Aluminum with 8' Davit Arm	Aluminum	40				$16.62				0				$0
27	Aluminum with 2-6' Double Davit	Aluminum	30				$12.56				8				$1,206
66	Aluminum, Ornamental, Post-Top	Aluminum	16				$9.27				2				$222
69	Alunimum, Smooth Techtra Ornamental	Aluminum	18				$19.11				19				$4,357
63	Fiberglass, Ornamental Black	Fiberglass	14				$11.77				161				$22,740
57	Fiberglass, 2-Piece, Color may vary	Fiberglass	20				$5.48				379				$24,923
61	Fiberglass, 2-Piece, Gray	Fiberglass	30				$8.91				1,395				$149,153
68	Fiberglass, 2-Piece, Color may vary	Fiberglass	35				$8.70				44				$4,594
16	Fiberglass, Anchor Base, Gray or Black	Fiberglass	35				$11.87				2				$285
35	Fiberglass, Direct Bury with Shroud	Fiberglass	18				$7.43				113				$10,075
79	Aluminum, Fluted Ornamental, Pendant	Aluminum	18				$0.00				0				$0
81	Aluminum, Non-Fluted Ornamental, Pendant	Aluminum	22				$0.00				0				$0
85	Fiberglass, 1-Piece, Anchor Base, Color May Vary	Fiberglass	25				$10.55				0				$0

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

					Monthly Tariff Price			DAX Monthly Tariff Price				Annual	Revenues		
Code	Description	Type	Size	kWh	Fixed	Energy	Total	Fixed	Energy	Total	Count	MWh	Fixed	Energy	Total
86	Fiberglass, 1-Piece, Anchor Base, Color May Vary	Fiberglass	30				$12.89				0				$0
91	Aluminum, Regular with Breakaway Base, 8' Arm	Aluminum	35				$17.93				0				$0
93	Aluminum, Double-Arm, Smooth	Aluminum	25				$15.05				0				$0
95	Aluminum, Smooth, Black, Pendant	Aluminum	23				$18.30				0				$0
97	Aluminum, Regular with Breakaway Base	Aluminum	25				$16.56				0				$0
99	Aluminum, Regular with Breakaway Base	Aluminum	30				$16.90				0				$0
Totals											8,879				$768,778
Totals Luminaires and Poles															$4,063,546

SCHEDULE 50
RETAIL ELECTRIC VEHICLE (EV) CHARGING

PURPOSE

This retail Electric Vehicle (EV) charging schedule is a supplemental service that governs the use of PGE's charging network for EVs. This schedule does not impact, replace, or otherwise modify any base retail service under which a customer is currently served by PGE. This schedule is designed solely for the retail sale of electricity as a transportation fuel.

DEFINITIONS

Direct Current Quick Chargers (DCQC) or Direct Current Fast Chargers (DCFC) – individual chargers that provide service at approximately 50 kW of peak demand or greater.

Electric Avenue Sites – Stations in PGE's service area that are listed as part of Electric Avenue on portlandgeneral.com.

EV User – An EV driver or operator who uses the PGE charging Station. This does not have to be a PGE customer.

Holidays – refers to New Year's Day (December 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November, and Christmas Day (December 25). If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

Idle Fee – refers to the fee charged to customers if their vehicle remains plugged into a charger after a 10-minute grace period when their vehicle has finished charging.

Income Qualified – Customers who qualify for PGE's Income Qualified Bill Discount (IQBD) program.

Level 2 Chargers - individual chargers that are capable of providing service at approximately 7 kW.

Off-Peak – refers to all other hours outside of the On-Peak period.

On-Peak – refers to the hours of 5~~3~~ PM to 9~~8~~ PM on weekdays, excluding holidays.

Session – each unique charging event in which a customer connects a vehicle to a PGE charger.

Station – the location of a PGE charging facility, consisting of one or more DCQC and/or Level 2 Chargers.

~~AVAILABLE~~

~~The service described in this schedule is available – through a point-of-sale transaction or a monthly subscription, depending on EV User preference – as requested, and is intended for use at PGE's EV charging Stations.~~

~~This schedule is not available for any use other than the purchase of retail electricity as a transportation fuel.~~

SCHEDULE 50 (Concluded)

AVAILABLE

The service described in this schedule is available ~~–~~through a point-of-sale transaction ~~or a monthly subscription, depending on EV User preference – as requested,~~ and is intended for use at PGE's EV charging Stations.

This schedule is not available for any use other than the purchase of retail electricity as a transportation fuel.

APPLICABLE

This schedule is available to all EV Users of PGE's EV charging Stations.

RATE

~~EV Users requesting service under this schedule may choose between a point-of-sale option, pre-pay, or a monthly subscription. EV Users may purchase a monthly subscription for use at Electric Avenue sites.~~ Pricing is as follows:

	~~Flat Fee~~Off-Peak Fee (all hours)*	On-Peak Charging Price	Idle Fee
Direct Current Fast Charger	$~~5.00 per Session~~$0.30 per kWh	~~Flat fee + $0.19 per kWh~~$0.58 per kWh	$0.40 per minute after 10 minutes
Level 2 Charger	~~$3.00 per Session~~$0.12 per kWh	~~Flat fee + $0.19~~$0.40 per kWh	$0.10 per minute after 10 minutes
Income Qualified DCFC Charger*	$0.24 per kWh	$0.52 per kWh	$0.40 per minute after 10 minutes
Income Qualified Level 2 Charger	$0.10 per kWh	$0.32 per kWh	$0.10 per minute after 10 minutes
~~**Monthly Membership**~~			
~~**Single Purchase**~~	~~$25.00 per month~~	~~$0.19 per kWh~~	
~~**Multiple Purchase****~~	~~$20.00 per month~~	~~$0.19 per kWh~~	

* Income qualified customers must qualify by entering the phone number associated with their PGE account into the charging station app or by calling the charging station's customer service. Customers must already be enrolled in the IQBD program.~~The flat fee is also the total charge during the Off-Peak period.~~

** ~~Monthly memberships may be purchased at a discounted price of $20 per month when buying at least 50 memberships at once.~~

~~The monthly membership subscription replaces the pay per-Session flat fees at Electric Avenue sites, but does not include the peak-time price.~~

~~If an EV User has selected the per-Session option, payment~~Payment will be made via credit card or other applicable payment method at the PGE charging Station, via the charging station's mobile app, or via calling the charging station's customer service.

SPECIAL CONDITIONS

1. This schedule is designed for retail service to drivers or operators of EVs. EV User-owned EV chargers are not eligible for service under this retail charging rate.

~~The pricing listed in this tariff is part of a pilot program and is subject to change.~~

2. EV Users may not request service under this schedule for any purpose other than the purchase of electricity from PGE to fuel the customer's vehicle(s) at PGE's EV charging Stations.

SCHEDULE 56
COMMERCIAL ELECTRIC VEHICLE MAKE-READY PILOT AND TRANSPORTATION ELECTRIFICATION LINE EXTENSION ALLOWANCE

PURPOSE

This Commercial Electric Vehicle (EV) Make-Ready Pilot provides eligible Fleet and Non-Fleet Customers with incentives to install Electric Vehicle charging infrastructure to support fleet and personal electric vehicles at fleet, commercial, workplace, and multifamily sites. The overarching goals of the pilot for both Fleet and Non-Fleet Customers are to:

- Evaluate the methods and incentives used to support both Fleet and Non-Fleet Customers' electric transportation transition;
- Create a network of demand side resources to reduce the costs of serving EV loads by supporting efficient grid operation and future renewables integration; and
- Generate empirical data that can be used to inform existing utility analyses, support customers transitioning to electric vehicles, and develop future products and programs.

The primary goals of the pilot for Fleet Customers are to:

- Enable and support the electrification of commercial, public (municipal, county, state, federal), school, non-profit and transit fleets by reducing customer cost and complexity associated with transitioning to electric fuel;
- Better understand the Fleet Customer and barriers and opportunities in the fleet electrification market; and
- Identify areas for utility process improvement with respect to fleet electrification.

The primary goals of the pilot for Non-Fleet Customers are to:

- Support the equitable electric transportation transition at commercial, workplace, and multifamily locations by reducing costs and complexity for property owners;
- Gain insight and information to better understand the barriers for Non-Fleet Customers and users of public and semi-public charging infrastructure; and
- Identify areas of utility process improvement for non-fleet commercial electrification and make ready infrastructure deployment.

The Fleet Transportation Line Extension Allowance (TLEA) provides eligible Fleet Customers a monetary allowance to aid in the installation of EV make-ready infrastructure to enable and support the electrification of commercial, public (municipal, county, state, federal), school, non-profit and transit fleets by reducing customer cost and complexity associated with transitioning to electric fuel. The Fleet TLEA replaces the Fleet Commercial Electric Vehicle Make-Ready Pilot upon full reservation of all funds available in the pilot.

AVAILABLE

In all territory served by PGE.

SCHEDULE 56 (Continued)

APPLICABLE

This ~~pilot~~ Tariff is applicable to nonresidential customers within PGE's service area.

DEFINITIONS

~~Activation Date – date that PGE first determines an EVSE is Operational.~~

Electric Vehicle Supply Equipment (EVSE aka Charger) – the device, including the cable(s), coupler(s), and ~~embedded software~~other associated hardware, installed for the purpose of transferring electricity between the ~~electrical~~ Make-Ready Iinfrastructure ~~at the Site~~ and the EV.

Electric Vehicle Service Provider (EVSP) – provider of ~~connectivity~~ the software platform that manages and collects data from the ~~across a network of~~ EVSE(s).

Fleet Customer – A nonresidential customer installing EVSEs at a fleet site for use by EVs owned or leased by Nonresidential Customers.~~for the purpose of the use or operation of their fleet of vehicles.~~

Line Extension – has the same meaning as set forth in Rule I.

Line Extension Allowance – has the same meaning as set forth in Rule I and is calculated per Schedule 300.

Line Extension Cost – has the same meaning as set forth in Rule I.

Make-Ready Cost – estimated actual cost of the acquisition, construction or installation, including costs for upgrades for the Make-Ready Infrastructure.~~the cost to design and construct and/or upgrade the Make-Ready Infrastructure~~ and Line Extension, excluding those accounted for in the Line Extension Cost.

Make-Ready Infrastructure – the infrastructure at the Site that~~to~~ delivers electricity from the Service Point to the EVSE~~(s)~~, including any panels, stepdown transformers, conduit, wires, connectors, meters, and any other necessary hardware.

Make-Ready Port – Make-Ready Infrastructure constructed in a way that supports the future installation of EVSEs with the corresponding number of ports. For example, a site constructed with Make-Ready Infrastructure for five dual-port EVSEs would have ten (10) Make-Ready Ports.

Non-Fleet Customer – A nonresidential customer installing EVSEs at commercial, workplace, multifamily, or other sites for use by EVs owned or leased by Residential Customers.

Operational – an EVSE installed at the Site is able to transfer energy between the Site wiring and the EV, with any applicable payment methods (e.g., credit card, phone app, subscription card), and transmitting operational data (e.g. energy usage, session start/end times) to the Qualified EVSP.

SCHEDULE 56 (Continued)

DEFINITIONS (Continued)

Qualified EVSE – ~~list of qualified~~ EVSE~~(s), determined by~~ that is on PGE's qualified products list.

Qualified Level 2 EVSE – An EVSE on PGE's qualified products list that provides Alternating Current (AC) electricity to the EV at 208 or 240 volts.

Qualified EVSP – ~~list of qualified~~ EVSP(s), ~~determined by~~that is on PGE's qualified products list.~~.~~

Qualified Service Schedule – list of qualified service schedules, including Schedules 32, 38, 83, 85, and 89. The list of qualified service schedules may be expanded to include new rates in the future.

Service Point – has the same meaning as set forth in Rule B.

Site – has the same meaning as set forth in Rule B.

Site Activation Date – the date that PGE determines the first EVSE at the Site is installed and Operational. PGE will provide Customer with written notice of the Site Activation Date.

Site Owner – entity holding title to the Site.

ELIGIBILITY

Eligible Fleet Customers are nonresidential customers that use or operate fleets (including, but not limited to, commercial, non-profit, public, school or transit fleets) within PGE's service territory installing a minimum of 70 kW of EV charging. Eligible Fleet Customers must own or lease the Site.

Eligible Non-Fleet Customers are nonresidential customers that are installing a minimum of 8 Qualified Level 2 EVSE Ports at existing commercial, workplace, or multi-family properties and are intended to be used by EVs owned or leased by Residential Customers. Eligible Non-Fleet Customers must own, lease, or manage the Site, and not have any active construction occurring at the site at the time of installation.

Eligible Fleet TLEA Customers are Fleet Customers who own, lease, or manage the Site and participate in the TLEA with a minimum 10-year total Energy Commitment of 400,000 kWh.

ENROLLMENT

Commercial Electric Vehicle Make-Ready Pilot:

The customer enrollment period for eligible Fleet Customers will be open through December 2025, or until available funds for the pilot have been fully reserved. Eligible customers may apply at PortlandGeneral.com and enroll by signing a participation agreement.

SCHEDULE 56 (Continued)

ENROLLMENT (Continued)

The enrollment period for eligible Non-Fleet Customers will be open through December 2025, or until available funds for the pilot have been fully reserved. Eligible customers may apply at PortlandGeneral.com and enroll by signing a participation agreement.

Upon full reservation of the fleet incentives in the commercial electric vehicle make-ready pilot, eligible customers may apply for the Fleet TLEA at PortlandGeneral.com and enroll by signing a participation agreement and meeting other program requirements.

INCENTIVE

Fleet Customers will pay for the Make-Ready Cost, less a custom incentive. The custom incentive will be calculated as the lower of the following amounts:

- Estimated Year 5 EVSE annual energy use x Line Extension Allowance x 7.5; or
- The participant's Make-Ready Costs; or
- $400,000.

Non-Fleet Customers will pay for Make-Ready Cost and Line Extension costs less an incentive not to exceed $17,000 per Make Ready Port. Non-Fleet Customers receiving the incentive cannot also receive a Line Extension Allowance for the same project. The incentive will be calculated as the lower of the following amounts:

- $17,000 per Make-Ready Port;
- The participant's Make-Ready Costs; or
- $204,000.

Fleet TLEA Customers will pay for the Make-Ready Cost and Line Extension Cost less an incentive. Fleet TLEA Customers receiving the incentive cannot also receive a Line Extension Allowance for the same project. The incentive will be calculated as the lower of the following amounts:

- Committed 10 year total kWh × service schedule Line Extension Allowance × 1.4
- The participant's Line Extension Cost plus Make-Ready Cost
- $450,000

SPECIAL CONDITIONS

1. Participation in this ~~pilot~~ tariff is not mandatory to install EV charging equipment.

2. Any chargers installed as a part of this ~~pilot~~ tariff must receive service on one of PGE's Standard Service Schedules. The customer's charges for electricity service under any of PGE's Standard Service or Direct Access Service schedules are not changed or affected in any way by participating in this schedule and are due and payable as specified in those schedules.

SCHEDULE 56 (Con<u>cluded</u>~~tinued~~)

SPECIAL CONDITIONS (Continued)

3. ~~For both Fleet and Non-Fleet Customers,~~ PGE will locate, design, install, own, operate and maintain the Make-Ready Infrastructure. For Fleet Customers, EVSE(s) will be separately metered from any other load at the Site. EVSE(s) may be separately metered at Non-Fleet Customer sites.

4. The Site Owner may be required to grant an easement to PGE to maintain PGE-owned facilities.

5. If the final design of the Make-Ready Infrastructure is estimated to cost in excess of $15,000, PGE may require the customer to submit a deposit prior to proceeding to final design and enrollment. The deposit will be the amount of the estimated final design costs and will be applied to the Make-Ready Costs or refunded upon the participating customer's enrollment in the Pilot. If the customer does not enroll, the deposit will not be refunded.

6. If the final design of the Make-Ready Infrastructure has been completed and the Customer does not enroll in ~~the Pilot~~<u>this tariff</u>, the Customer may be required to reimburse PGE for final design costs and any other associated expenses that PGE incurs due to the cancellation of the project.

7. If the participating Fleet Customer's custom incentive is in excess of $250,000, the participating Fleet Customer agrees that PGE may verify its creditworthiness at any time and seek financial security to ensure the participating Fleet Customer is able to meet its obligations as set forth in the participation agreement.

8. The participating Fleet Customer is responsible for the procurement and installation of at least one new Qualified EVSE(s) within 6 months of PGE's completion of the Make-Ready Infrastructure. The participating Non-Fleet Customer is responsible for the procurement and installation of all Qualified Level 2 EVSE(s) within 12 months of PGE's completion of the Make-Ready Infrastructure.

9. The participating customer must maintain the EVSE(s) on a Qualified Service Schedule for 10 years following the <u>Site</u> Activation Date<u>.</u> ~~of the first Qualified EVSE installed at the Site.~~

10. The participating customer will ensure the EVSE(s) remain Qualified EVSE(s) and Operational for 10 years following the <u>Site</u> Activation Date<u>.</u> ~~of the first Qualified EVSE installed at the Site.~~

11. The participating Fleet Customer will adhere to an energy usage plan that sets forth the minimum amount of energy the participating customer commits to using over the 10 years following the <u>Site</u> Activation Date ~~of the first Qualified EVSE installed at the Site~~, but in no event will the minimum energy usage amount be less than the Estimated Year 5 energy use x 6. <u>The participating Fleet TLEA Customer will adhere to an energy usage plan that sets forth the minimum amount of energy the participating customer commits to using over the 10 years following the Site Activation Date.</u>

SCHEDULE 56 (Concluded)

SPECIAL CONDITIONS (Continued)

12. ~~The participating~~ Fleet and Non-Fleet ~~c~~Customers participating in the Pilot will authorize and require the Qualified EVSP to provide operational data (e.g. charging session data, energy interval data) to PGE, and~~,. The participating customer~~ agree~~s~~ to allow PGE and its agents and representatives to use data gathered as part of the pilot in regulatory reporting, ordinary business use, industry forums, case studies or other similar activities, in accordance with applicable laws and regulations and to participate in PGE-led research such as surveys.

13. If the Site changes ownership or lesseeship, participation in this~~e pilot~~ tariffmay be assumed by the new owner or lessee if it is willing to meet the ~~pilot~~ requirements. The participating Fleet Customer will be responsible for any pro-rata reimbursement for estimated minimum usage deficiencies between the participating customer's original energy usage plan and the new customer's energy usage plan.

14. In the event the participating customer breaches or terminates the participation agreement, the participating customer will reimburse PGE the pro-rata value of the custom incentive, calculated over the 10-year term.

RULE C (Continued)

Short Term Emergency Curtailment (Continued)

The Company's Curtailment Plan and underlying operating procedures include, but are not limited to, steps for implementing rotating outages. During rotating outages the Company would discontinue Electricity Service to a specific number of circuits for approximately one-hour periods. If, after the first hour, system integrity were still in jeopardy, the circuits initially curtailed would have service restored while a second block of circuits would simultaneously have service discontinued. This cycle would continue until the Company determined that system emergency conditions no longer existed. Facilities deemed necessary to public health, safety and welfare are excluded from the rotating outage, as well as feeders serving Customers participating in the Schedule 88, Load Reduction Program.

During system emergencies, Customers having their own generation facilities or access to Electricity from non-utility power sources may choose to use energy from those other sources. The Company will not initiate its Curtailment Plan to avoid the purchase of high priced power. The Curtailment Plan is periodically updated and submitted to the Commission.

C. **Limitation of Liability**

The Company and its authorized contractors ~~is~~ are not liable to Customers, ESSs or any other person or entity for any interruption, suspension, curtailment or fluctuation in Electricity Service, or for any loss or damage caused thereby, resulting from:

1) Causes beyond the Company's reasonable control;
2) Repair, maintenance, improvement, renewal, or replacement of Facilities, or any discontinuance of service that the Company determines is necessary to permit repairs or changes to its Facilities or to eliminate the possibility of injuries to persons or damage to the Company's property or property of others. To the extent practical, such work will be done in a manner that will minimize inconvenience to the Customer, and whenever practical and applicable, the Customer will be given reasonable notice of such work, repairs, or changes;
3) An ESS's failure to abide by the terms of the ESS Service Agreement or the Tariff; Automatic or manual actions taken by the Company, including but not limited to Emergency Curtailments, that in its opinion, are necessary or prudent to protect the performance, integrity, reliability, or stability of the Company's electrical system or any electrical system with which it is interconnected; and
4) Actions taken by the Company to curtail Electricity use at times of anticipated resource deficiency in accordance with the applicable provisions of this Tariff.