BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Maria Pope
Brett Sims

February 15, 2023

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I. Introduction

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

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 Strategy, Regulation and Energy Supply.

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:

- Provide the context for our rate case filing, including our company's mission, strategic vision and priorities, and the substantial changes in our operating environment that have occurred and are expected to continue. These changes include historically high inflation, increasing extreme weather events, volatile energy markets, significant and urgent policy mandates, and rising customer expectations.
- Summarize key expenditures necessary to deliver safe, reliable power to customers, including investments in the Faraday Resiliency and Repowering Project, grid reliability and resiliency investments, and increased costs associated with inflation, fuel and power purchases, vegetation management, information technology (IT), and cyber and physical security.
- Summarize key policy proposals that seek to better align key regulatory mechanisms with decarbonization and resource adequacy requirements.

- Summarize the proposed average base customer price increase for 2024 of 9.5%, and the average net variable power cost (NVPC) increase for 2024 of 4.5% (the total proposed price changes for specific classes of customers are detailed in PGE Exhibit 1300, Pricing).
- Provide Commissioners and Commission Staff of the Public Utility Commission of Oregon (Commission) and stakeholders a roadmap for evaluating our filing.

Our testimony is organized according to these primary objectives.

Q. Please provide a brief description of PGE.

A. As a vertically integrated,[1] regulated electric utility company, PGE proudly serves more than 900,000 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 south to 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.

Q. Please state PGE's mission and strategy.

A. PGE exists to power the advancement of society. We energize lives, strengthen communities, and foster energy solutions that promote social, economic, and environmental progress. Together with customers, communities, partners, and investors, we are creating a safe, reliable, clean, and accessible energy future. We are actively removing greenhouse gas

[1] In the Commission's SB 978 investigation, the Commission well-articulated the value of a vertically integrated utility versus expansion of retail direct access in noting: "Moreover, it is more difficult to assure meeting the full suite of public policy goals and desired system outcomes in a competitive retail environment than in a regulated market structure." See the Commission's final report to the Oregon Legislature, SB 978 Actively Adapting to the Changing Electricity Sector, at p.16, available at: https://www.oregon.gov/puc/utilities/Documents/SB978LegislativeReport-2018.pdf

emissions from our system, electrifying the economy from transportation to homes and buildings, and offering products and services that put customers in control of their energy journey. Our customers remain at the forefront of our priorities, driving us to continuously explore and innovate, deploy new technologies, simplify processes, and reduce costs as we strive to deliver exceptional value. The investments and actions reflected in this rate case are critical to fulfilling these commitments for our customers and communities.

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

A. Yes. We continue to provide safe, reliable, and reasonably priced electricity that is increasingly clean and sustainable, while also managing the impacts of rising costs due to historic inflation, challenging macroeconomic conditions, extreme weather, catastrophic events and public health crises, and volatile energy markets. Our customers and communities have endured and overcome unimaginable difficulties over the last few years – we are humbled by the perseverance and resiliency of our fellow Oregonians. At the same time, the urgency to address the imperatives of climate change and social justice has led to monumental policy changes which dramatically impact the energy sector and society more broadly. Given this unprecedented level of challenge and change, prioritization and making difficult choices in our planning, investments and operations are essential. PGE must continue to take steps to ensure safety, reliability and compliance with all applicable laws and rules governing our service. We are also accelerating our efforts in other key areas such as decarbonization, grid transformation, and beneficial electrification, but also understand that we cannot do everything all at once. Therefore, the actions and expenditures contained in this rate case were made with these considerations in mind. It is during these times that fulfilling our fundamental mission as an essential service provider and steadfast partner is most important.

Q. How is the rest of your testimony organized?

A. In the next section, we explain how this general rate case fits into the broader policy context of the Commission and the state of Oregon. Next, we summarize the average price increase proposed in this case and the primary drivers of that increase, as well as our efforts to manage costs and risks while still making essential investments to benefit customers. We then identify PGE's key proposals in this case and introduce the exhibits and witnesses who provide additional testimony in support of our requests. In the final section, we provide our qualifications.

II. Context for This Case

Q. What is the context for this rate case?

A. We are filing this case in a time of extraordinary challenges and transformation. Climate change and extreme weather events, adverse macroeconomic conditions, geo-political instability, volatile energy markets, decarbonization policies, evolving customer expectations, and severe 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 protected customers from unprecedented volatility in energy prices, while fulfilling our mission of providing safe, reliable, affordable, and increasingly clean electricity. In this rate case we propose investments and regulatory policy modifications that enable PGE to continue to be a nimble, customer- and community-focused partner with the financial strength to implement ambitious decarbonization measures at the least cost and risk while navigating the highly dynamic atmosphere described above.

Q. What are the drivers for this rate case?

A. The overarching driver for this rate case is to maintain PGE's ability to deliver safe, reliable, affordable power amid an uncertain and rapidly evolving environment. These challenges include: an urgent and momentous clean energy transition, increased frequency of severe weather and load events, volatile energy prices, constrained regional markets, cyber and physical security threats, increased push for beneficial electrification, inflationary pressures, and rapidly evolving customer expectations. To address these challenges, PGE is seeking recovery of investments for system reliability and resiliency, technology advancements to modernize and increase operational efficiencies, and to address increased costs due to inflation. This case further describes key investments such as the Faraday Resiliency and

Repowering Project and other critical grid reliability and resiliency expenditures, including vegetation management and cyber and physical security, increased costs due to fuel and power purchases, and information technology upgrades to enhance business processes and improve operations.

Q. How do economic conditions impact PGE and our customers?

A. The COVID-19 pandemic and the ensuing economic impacts have resulted in exceptionally high inflation levels not seen for several decades. The Bureau of Labor Statistics Consumer Price Index - Annual Average Index shows that inflation increased 8.0% in 2022, following a 4.7% annual increase in 2021. PGE is not immune to these inflationary pressures. The cost of general business has risen sharply for all industries and the increases have been particularly acute in the energy sector. Throughout the testimony we demonstrate the impacts of macro-level and inflationary cost increases beyond PGE's control on energy market prices, insurance, interest rates, labor, materials, and technology. At the same time, the testimony also details PGE's actions to prudently manage costs, while increasing operational effectiveness and providing safe and reliable service to our customers.

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

A. PGE and our customers face increasing impacts of climate change across all aspects of our operations and daily lives. At the same time, electric utilities like PGE play a fundamental role in implementing the vital decarbonization and resiliency actions necessary to address these challenges. This intersection of roles – increasing operational challenges combined with necessary leadership at the highest levels – has created a very complex operating and policy environment for both PGE and our customers.

More frequent extreme weather conditions underscore the importance of wildfire mitigation and vegetation management activities. Further, higher insurance costs driven by worsening overall market conditions and catastrophic events have resulted in premium increases while available coverage is decreasing. Increasing cyber and physical security and emergency management costs, due to additional security risks and the increased likelihood of natural disasters (e.g., wildfires, severe storms, floods, etc.), drive the need to harden and protect critical energy infrastructure.

Ever-increasing severe winter storms (wind, ice, floods), intense summer heat, and growing weather variability have dramatically affected customer heating and cooling patterns. These extreme weather conditions have resulted in record-setting summer and winter peak loads over the last two years. For summer, a record peak of 4,453 MW was set in 2021 and for winter, a record peak of 4,113 MW was set in December 2022, eclipsing the prior winter peak record set nearly a quarter century ago in 1998. This climate uncertainty when coupled with the transition to new clean energy technologies in Oregon and the region has placed increasing pressure on the cost and risk to reliably serve our customers as the availability of capacity has tightened and energy prices skyrocket 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 2024 and beyond.

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

A. PGE continues to see an influx of residential customers into our service territory, with a new customer connect growth of over 30,000 residential and almost 7,000 non-residential from the beginning of 2022 forecasted through the end of the 2024 test year.[2] The COVID-19 pandemic

[2] *See* PGE Exhibit 1103 for customer connect data.

further highlighted that customers of all types rely on us to provide highly reliable power, particularly as large numbers conducted work, business, and education remotely. We expect this remote and hybrid trend to continue. Further, growth in the high-tech sector including several new data centers and other new businesses emphasizes the important role of economic development in our service territory. Customers considering locating in PGE's service territory expect safe, reliable, and affordable power that is also cleaner. Meeting these expectations requires thoughtful planning, strategic investments, effective resource deployment, and corporate financial stability and responsibility to do so affordably.

Finally, increased electrification in 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. 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.

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 actively adjusting our structured transactions and power cost hedging practices to address changing market conditions. As part of those efforts, we have expanded our regional strategy, seeking partnership opportunities that leverage organizational synergies and yield net benefits for customers. Agreements with Douglas County PUD and a wholesale industrial energy user are examples of mutually beneficial relationships that are helping to deliver key decarbonization, flexibility and resource adequacy outcomes.

PGE has also focused on maximizing plant operations cost-effectively. Plant operational efficiencies have led to increased availability during peak demand periods for PGE-owned plants while at the same time keeping generation operations and maintenance (O&M) costs relatively flat in real dollars since 2017.

These efforts, in conjunction with PGE's robust and diverse portfolio and system, substantially mitigated the impact of extreme energy market conditions and prices for customers. During the period of January 2019 through 2023, PGE's power cost customer price increases totaled 16.4%, or an average of roughly 4% per year. Over the same period wholesale electricity prices increased by 229%.

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 unprecedented fuel and inflation costs, and investments in the longevity of clean and diverse, non-emitting resources such as the Faraday Resiliency and Repowering Project, and other resource modernization efforts. Additionally, we have proposed important modifications to certain regulatory mechanisms, including revision of our Power Cost Adjustment Mechanism (PCAM) and revenue decoupling mechanisms, which together create better overall alignment with achieving decarbonization targets and adapting to today's market dynamics.

Another key component of our clean energy transition is the advancement of our Virtual Power Plant (VPP). The VPP will enable 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 investments. The VPP will also provide data to support analytics for improved identification of when additional renewable energy resources are needed to meet peak customer demand, allowing for better resource planning. Through the VPP, DERs and flexible loads can help us achieve cost-effective decarbonization, 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 support reliability and advanced resource planning. It will aggregate the expansion of local 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.

The Faraday Resiliency and Repowering Project is an investment that will bring carbon-free and sustainable energy benefits for generations to come. Investments in cyber and physical security and vegetation management are critical to ensuring a safe, reliable, secure, and resilient system. Further, we have made investments in hundreds of individual projects, large and small, to modernize, strengthen, and upgrade our Transmission and Distribution (T&D) system for customer growth, enhanced reliability, and resilience. The investments

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

reflected in this rate case will meaningfully contribute to the realization of our strategy to deliver a clean energy future while managing dynamic risk and delivering exceptional value for our customers.

Q. Regarding electric system decarbonization, does the vertically integrated model allow PGE to do the greatest good for the greatest number of customers?

A. Yes. Since the inception of universal basic electric service, the vertically integrated utility has demonstrated an ability to manage risk and assure prudent least-cost investments. Now the challenges of climate change, public health crises, and economic and energy market disruptions compound risks and highlight the importance of the utility as a steady, well-established community partner capable of leveraging low-cost investment to advance Oregon's clean energy transition. The regulated utility model provides regulators, policymakers, and stakeholders transparency and strong oversight in how we transition to a clean energy future while continuing to provide safe, reliable, and affordable service. No other business model similarly serves the public good and affords these long-standing benefits.

III. Requested Change in Prices

Q. Please summarize PGE's requested price change.

A. We request that prices be adjusted for both base business and net variable power costs to yield approximately $338 million in increased revenue requirement. This represents a roughly 9.5% increase attributable to base rates and a 4.5% increase attributable to fuel and power costs, for a total average increase of approximately 14.0% in customer prices beginning January 1, 2024. The primary drivers of this requested change in prices, along with the impacts by customer class, are detailed in PGE Exhibit 200, Revenue Requirement, and PGE Exhibit 1300, Pricing.

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 ensure system reliability and resiliency, safety and security, and affordability as the foundation for delivering on our obligation and commitment as an essential service provider. We have also made critical investments and enhancements to our operations, services, and engagement to advance a clean energy future where all PGE customers and communities are able to fully participate and benefit.

Q. How does PGE's price increase in this case compare to its prior rate cases?

A. PGE recognizes this is a significant price increase and we are very mindful of the impact that the increase will have, and the central role electricity plays in the lives of our customers and the health and vitality of our communities. However, PGE is not immune to the impacts of market-driven fuel and power costs, supply chain and inflation, which have affected our business across nearly every segment. The financial health of PGE is critical to our ability to continue to serve customers safely, reliably, and affordably, and to successfully meet state decarbonization goals while mitigating the impacts of climate change.

Q. How does PGE's requested price change compare to increases proposed by other electric utilities within the past year?

A. Of PGE's proposal to increase rates an average of 14.0%, approximately 9.5% is attributable to base rates and approximately 4.5% is attributable to fuel and power costs. This combined increase is below the average of proposed increases made in rate cases by vertically integrated electric utilities across the United States since May 2022. According to S&P Global, of the 14 pending rate cases filed within the past nine months, the average increase sought was 16.8% with a median increase of 15.8%.

Q. Isolating power costs from rates, how have PGE's base rate increases compared to inflation?

A. The Commission approved base rate increases for PGE during the period from 2019 to 2022 of 1.6% for the investment in the Wheatridge wind facility and 0.5%[4] related to its 2022 GRC. During the same period, load growth contributed approximately 3.2% to PGE's base rate revenue increase. This 5.3% increase in total compares to realized inflation from 2019 to 2022 of 14.4%.

The combination of realized and projected inflation over the period from 2019 to 2024 is expected to be approximately 22.5%. Load growth over the same five-year period is forecast at a total of 9.1%. With increases outside of load growth to base rates of only 2.1%, inflation has outpaced PGE's base rate growth by over 10%. We are very pleased to deliver our service to customers at prices that are well below inflation given such challenging economic conditions. However, it is also clear that the company is unable to maintain this level of

[4] Docket No. UE 394, Order No. 22-129 at 1.

discrepancy between economic realities and our recovery of costs through customer prices, while still delivering on our core service obligations and critical policy commitments.

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

A. We have a continued firm commitment to manage costs, streamline processes, learn from others, and maintain a culture of continuous improvement that benefits customers through increased value and reduced long-term cost impacts. Our efforts to manage O&M costs and improve operational efficiencies have resulted in a personnel productivity increase in some areas by upwards of 33%. Operational productivity has increased while holding overall cost trends stable. In addition, we have continued to improve and enhance service reliability as evidenced by a reduction in 2022 over the prior year in the duration of systems events impacting business by 13%.

Our total recordable incident rate has improved 37% in the last five years. To manage declining PGE field crew staff, PGE has made investments at our Sherwood Training center to hire and train more PGE crew personnel. An additional 24 pre-apprentices started last May, bringing the pre-apprentice/apprentice pipeline to 61 employees.

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 that reduce costs, diffuse risk, and hedge against extreme market conditions. These include peak for super-peak exchanges and flexible wholesale transactions that provide the ability to recall energy and capacity to meet peak customer demand while avoiding high priced purchases.

In addition, over recent years, we have deployed cloud-based services that provide us with a new level of flexibility in how we manage and organize IT capabilities. Using cloud-based services instead of the traditional on-premises approach reduces IT costs. The use of this technology increases efficiency, reduces enterprise risk and increases financial transparency, enabling better informed financial decisions. Lastly, it also enhances customer service by increasing elasticity to support increased usage and resiliency, especially during major outage events such as storms.

Q. How does PGE help customers mitigate price impacts?

A. To mitigate price impacts while still allowing us to make essential system investments, we manage our costs carefully and offer an array of programs to help customers manage their energy usage and reduce bill impacts.

We understand that the cost burden for essential services like electricity is most acute for low-income households and vulnerable individuals, and that any price increases for these customers are particularly difficult. To help ease this burden, PGE worked proactively with stakeholders and the Commission to successfully launch an income-qualified bill discount (IQBD) program, which provides a 15-25% discount for low-income customers. We have over 50,000 customers enrolled as of January 2023 (representing roughly 6% percent of residential customers) and expect another 45,000 to enroll this calendar year. The IQBD program benefits largely offset the proposed rate increase for this group of customers. PGE has additional bill assistance resources and programs available to help customers, including preferred due date and payment plans, Energy Assistance funds, and a Medical Certificate Program.

PGE also offers a suite of tools for customers to manage their energy usage and help mitigate 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. For multi-family, PGE offers a Multi-Family Water Heater program to adjust water heating to times when demand is low, giving PGE more options to cost-effectively balance our resources. For small and medium commercial customers, PGE offers a Smart Thermostat program where it adjusts the thermostat between one to three degrees during peak load events to reduce costs of participating customers. 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 customers are participating in and benefitting from these programs.

Q. In addition to PGE's efforts to manage and mitigate costs, is PGE pursuing other sources of funding on behalf of its customers to help maintain affordability while pursuing ambitious and urgent decarbonatization and policy goals?

A. Yes. In November 2021, the Infrastructure Investment and Jobs Act (IIJA) became law, resulting in unprecedented levels of government funding—$1.2 trillion—for a wide range of programs to be administered by various federal agencies and for which electric utilities are uniquely positioned to submit grant applications. Then, in 2022, the Inflation Reduction Act (IRA) became law, resulting in a second monumental piece of legislation containing a range of grants, tax credits and incentives for a wide array of clean energy development. IIJA and

IRA grant funds and incentives could reduce the cost impacts to customers of meeting the requirements of HB 2021. Successful grant applications could also provide critical funding for transportation electrification and distribution system investments. Some of the key areas of funding identified include grant and loan programs for transportation electrification, grid resiliency, climate and wildfire adaptation and resiliency, clean energy, smart grid investment, carbon reduction, hydrogen, and expanded and advanced energy efficiency. While billions of dollars have been set aside for clean energy and projects to mitigate the effects of climate change, including more than $62 billion to the U.S. Department of Energy for new and existing programs, PGE expects to see a highly competitive process among utilities and other industries to secure a portion of these funds.

PGE set up a team to aggressively pursue competitive federal grants to benefit customers. Through February 10, 2023, we have submitted ten concept papers or grant applications totaling $478 million in total grant requests, as well as $85 million in Federal Emergency Management Agency (FEMA) Building Resilient Infrastructure and Communities (BRIC) applications. Projects include new applications to mitigate wildfire risks and a grant submitted in partnership with the Confederated Tribes of Warm Springs to strengthen the transmission capacity in the region which will help as we add new carbon-free energy.

Q. Will the results of this rate case affect PGE's future access to and cost of capital to fund investments?

A. Yes. The results of this case, as filed, will be important to PGE's ability to cost-effectively fund capital investments, meet financial obligations, and provide an opportunity for our providers of capital to receive a reasonable return on their investment, which in turn benefits our customers by giving investors the incentive to provide access to low-cost capital that supports the delivery of reliable, affordable service to customers. Achieving decarbonization targets that are critical to addressing climate change and required in accordance with Oregon's mandates under HB 2021 depends on investor support and significant new funding from capital markets.

In addition, while we are requesting an increase in our authorized return on equity (ROE) from 9.5% to 9.8%, our proposal is limited to a level that is below peer utilities whom we compete with for capital. Our risk profile supports an even higher ROE request as demonstrated in PGE Exhibit 1000, Cost of Capital.

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 proposals:

- Increase to our revenue requirement by $338 million and prices by 14% on average. The requested price increase is the combination of an approximate 9.5% increase in base rates and an approximate 4.5% increase in fuel and power costs to be effective January 1, 2024. This request is discussed in more detail in PGE Exhibit 200;
- Approve PGE's incremental capital investments of $859 million, resulting in a total rate base of $6.3 billion as described in the testimony of various witnesses in this case;
- Approve an overall cost of capital of 7.06% percent, which is comprised of a capital structure of 50% equity and 50% long-term debt, and an ROE of 9.8% as described in PGE Exhibit 1000;
- Approve PGE's proposed modifications to modernize the PCAM, which is discussed in PGE Exhibit 400;
- Approve PGE's updates to power cost modeling and allow for review and inclusion of modeling enhancements between rate cases, discussed in more detail in PGE Exhibit 300;
- Approve PGE's proposal to rate base certain cloud-based IT prepaid expenses and investments to bolster physical and cyber security protections, as detailed in PGE Exhibit 600;
- Approve PGE's proposed implementation of "associated storage" for purposes of addressing battery storage within renewable automatic adjustment clause filings to

support renewable resource integration, discussed in more detail in PGE Exhibit 1300; and

- Concur with PGE's position that a deferral and an automatic adjustment clause (AAC) are two separate mechanisms with different purposes and, therefore, each AAC does not require a deferral filing in addition to the tariff filings, as described in PGE Exhibit 1400.

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, Revenue Requirement Manager, Regulatory Affairs summarize the overall $2,672 million test year revenue requirement, comparing the request with that most recently approved in our last general rate case Docket No. UE 394 (2022 test year). In Exhibit 200, we identify a specific Wildfire Mitigation revenue requirement that will be included in a separate tariff pending the outcome of a proposal by parties in Docket No. UE 412. This testimony also discusses our net rate base, plus associated depreciation and amortization expense, and unbundled results.
- In Exhibit 300, Erin Schwartz, Manager, Gross Margin and Power Cost Forecasting & Analysis, Darrington Outama, Senior Director, Energy Supply, and Stefan Cristea, Regulatory Consultant, Regulatory Operations provide the initial forecast of PGE's 2024 NVPC and discuss proposed enhancements to MONET modeling, as well as other inputs. They also compare the initial 2024 forecast with PGE's final 2023 NVPC forecast and explain the increase in expected per-unit NVPC.

- In Exhibit 400, Brett Sims, Vice President, Strategy Regulation and Energy Supply and Darrington Outama, Senior Director, Energy Supply 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 modification to the PCAM is imperative.
- In Exhibit 500, Anne Mersereau, Vice President, Human Resources, Diversity, Equity & Inclusion and Tamara Neitzke, Director of Total Rewards present PGE's total compensation costs for the 2024 test year, which include total labor costs, incentive pay, and employee benefits and describe how PGE's compensation philosophy is designed to address compensation challenges.
- In Exhibit 600, Jim Ajello, Senior Vice President, Chief Financial Officer (CFO), and PGE Treasurer and Greg Batzler, Senior Regulatory Consultant, Regulatory Affairs explain PGE's request for approximately $210 million in administrative and general (A&G) costs in 2024 and compare it to 2022 actuals of $213 million.
- In Exhibit 700, Larry Bekkedahl, Senior Vice President Advanced Energy Delivery and Bradley Jenkins, Vice President Utility Operations discuss T&D capital expenditures from May 1, 2022, through December 31, 2023, and incremental O&M activities and costs for the 2024 test year. They specifically discuss investment in routine vegetation management, grid modernization, and PGE's Distribution System Plan.
- In Exhibit 800, Larry Bekkedahl, Senior Vice President Advanced Energy Delivery and Bradley Jenkins, Vice President Utility Operations discuss the O&M expenses associated with PGE's long-term power supply resources. They discuss the recent plant

performance of our generation fleet and identify the major drivers of the 2024 test year O&M expenses related to PGE's generating plant operations as compared to actual 2022 O&M expenses. This testimony also supports investment in the Faraday Resiliency and Repowering Project.

- In Exhibit 900, Michaela Lynn, Senior Director, Customer Service and Dain Nestel, Director of Sales explain PGE's forecast of Customer Service O&M cost for the 2024 test year and compare them to 2022, which represents PGE's most recent actual results. In the 2024 test year discussion, notable changes since the 2022 GRC are discussed. They then describe the incremental TE program funding and TE program accomplishments. Finally, they discuss changes to the expected uncollectible expense related to recent Division 21 rulemaking, economic conditions and how uncollectible expense was calculated for the 2024 test year.
- In Exhibit 1000, Chris Liddle, Senior Director, Controller and Assistant Treasurer at PGE and Bente Villadsen, a Principal of The Brattle Group, estimate the cost of equity that PGE should be allowed an opportunity to earn on the equity portion of its rate base for the period starting January 1, 2024.
- In Exhibit 1100, 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 2024 test year energy and customer forecast.
- In Exhibit 1200, Robert Macfarlane, Manager, Pricing and Tariffs, and Ashleigh Keene, Regulatory Consultant in Pricing and Tariffs describe the methodologies and results of PGE's generation, transmission, distribution, customer service, and street lighting marginal cost of service studies.

- In Exhibit 1300, Robert Macfarlane, Manager, Pricing and Tariffs, and Christopher Pleasant, Senior Regulatory Analyst at PGE describe how the proposed tariff changes recover our 2024 revenue requirement to achieve fair, just, and reasonable prices for our customers and price changes to various supplemental schedules. Additionally, they discuss the decoupling mechanism and proposal for the definition of associated storage.
- In Exhibit 1400, Jaki Ferchland, Manager of Revenue Requirement, Regulatory Affairs and Greg Batzler, Senior Regulatory Consultant, Regulatory Affairs explain why the current process where PGE must always file deferral applications when an automatic adjustment clause has been established is administratively burdensome and unnecessarily duplicative since the applications should only be required in those circumstances where a deferral is truly warranted under Oregon Revised Statute (ORS) 757.259.

V. 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 the Vice Chair of the Electric Power Research Institute, and on the Executive Committee 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 in 1990, and a Master of Business Administration degree from George Fox University in 2001. 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 416

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Greg Batzler
Jaki Ferchland

February 15, 2023

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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 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 2024 test year forecast revenue requirement for the following components:

- Base business costs[1] of $2,671.5 million; and
- Wildfire Mitigation (WM) isolated revenue requirement of $33.0 million.

As discussed in PGE Exhibit 700, PGE is isolating all identifiable WM-related costs (both expense and capital) to be included within PGE Schedule 151, consistent with the Stipulation in Docket No. UE 412 (UE 412) between the Public Utility Commission of Oregon (Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), and PGE. While a full settlement was reached between PGE, Staff, and AWEC, the Oregon Citizens' Utility Board (CUB) is not a party to the Stipulation and a Commission order in the docket is expected during the pendency of this proceeding. As such, we provide here a WM revenue requirement, which, after being included within the proposed separate schedule, would reduce our base business request for pricing purposes. Because UE 412 has not yet been decided by

[1] Inclusive of Wildfire Mitigation costs.

the Commission, these costs are still effectively part of base rates; the following testimony will discuss PGE's 2024 revenue requirement with WM included unless specifically stated otherwise.

Q. What increase in revenue requirement does PGE request beginning January 1, 2024?

A. PGE requests a base business increase of $337.8 million or 14.5%, including WM-related costs,[2] which would become effective January 1, 2024. This increase is relative to the revenues we expect based on the following: 1) 2022 prices approved in Commission Order No. 22-129 in Docket No. UE 394 (UE 394); plus 2) the 2023 power costs reflected in PGE Schedule 125, as approved in Commission Order No. 22-427. However, by including 2023 Schedule 146 (Colstrip Power Plant Operating Life Adjustment) amounts within current and requested prices, PGE's requested increase of $337.8 million represents an approximate 14.0% increase in revenues.[3]

The revenue requirement proposed in this filing will allow PGE an opportunity to earn a 7.06% rate of return that includes a 9.80% return on average common equity (ROE) in 2024.[4] PGE Exhibit 201, columns 1 through 3, summarizes the development of PGE's 2024 revenue requirement for base business. In addition to presenting this integrated (bundled) revenue requirement, we also present and discuss our unbundled revenue requirement in Section VII.

Q. In the absence of a price increase, what is PGE's expected regulated ROE for 2024?

A. Without a price increase, we would expect PGE's regulated ROE to be approximately 2.24% in 2024, which is significantly lower than the currently authorized ROE of 9.50%.

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[2] Note that 2024 WM costs will be updated within Schedule 151 and be consistent with PGE's 2024 Wildfire Mitigation Plan, which will not be submitted until later in 2023.
[3] *See* PGE Exhibit 1300 for additional detail regarding PGE's overall percentage increase.
[4] As discussed in PGE Exhibit 1000, PGE proposes a 50/50 capital structure between debt and equity.

Q. What are PGE's test year and base year periods used in this filing?

A. PGE's test year is calendar year 2024 and the base year of most recent actual results is 2022. Rate base is established as of December 31, 2023.

Q. Does PGE's 2024 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. Consequently, no Colstrip operations and maintenance (O&M) or plant-related costs are included in PGE's 2024 revenue requirement. 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 Boardman Coal Plant (Boardman) included in PGE's filing?

A. No. Similar to Colstrip, all Boardman-related costs have been removed from both actual and forecasted results. Additionally, PGE set the collection amount for Boardman decommissioning to $0 beginning January 1, 2022, and we currently have no expectation to seek any additional amounts related to Boardman.

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

A. No. PGE's 2024 revenue requirement does not include any costs or benefits related to Clearwater. We are in the beginning stages of forecasting the annual expected costs and benefits of this project for ratemaking purposes and we expect to file a request under PGE's

Schedule 122, Renewable Resources Automatic Adjustment Clause, sometime in the third quarter of 2023 for the inclusion of Clearwater into customer prices consistent with the project being placed into service.

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

A. Yes. To help mitigate the impact of historically high inflation and offset increases resulting from 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 the entirety of the incentive program benefits customers and is a key part of all investor-owned utilities' total compensation;
- 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 employees and have been included in previous general rate cases;
- Removing approximately 50% of meals and entertainment costs based on 2022 actual meals and entertainment expenditures; and
- Incorporating forecasted efficiencies and O&M cost savings through our rigorous operational planning and budget process. For example, as discussed in PGE Exhibit 600, even in the face of heightened inflation and a tight labor market for highly skilled labor, PGE has achieved operation and staffing efficiencies that have

helped to keep Information Technology (IT) labor costs relatively flat from 2022 to 2024.

A. Summary of the Case

Q. Please summarize PGE's 2024 revenue requirement.

A. Table 1 below summarizes PGE's 2024 revenue requirement by major category and provides a comparison to the results of UE 394. We also list the PGE testimony that addresses each specific cost category.

Table 1
Revenue Requirement Summary
($millions)

Rev Req Category	UE 394 Approved	2024 Forecast	2024 WM	2024 Net of WM*	Exhibit	No.
Sales to Consumers	$ 2,034.0	$ 2,671.5	$ 33.0	$ 2,638.6	Rev Req	200
Other Revenue	32.3	39.7		39.7	Rev Req	200
Net Variable Power Costs	543.6	860.1		860.1	Rev Req	200
Production O&M	111.2	134.0		134.0	Production	800
Transmission O&M	19.5	22.4	1.5	20.9	T&D	700
Distribution O&M	145.8	209.8	23.3	186.4	T&D	700
Customer Service	89.7	107.2	0.2	107.0	Customer Svc.	900
A&G	180.9	209.8	0.2	209.6	Corp. Support	600
Depr. & Amort.	358.1	422.6	2.5	420.1	Rev Req	200
Other Taxes	157.0	192.6	1.5	191.1	Rev Req	200
Income Taxes	90.3	108.8	0.8	108.0	Rev Req	200
Operating Income*	**$ 370.1**	**$ 444.0**	**$ 3.1**	**$ 441.0**		
Return on Equity	9.5%	9.8%	9.8%	9.8%	ROE	1000

** May not sum due to rounding*

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 1000.

Q. How did you develop the 2024 revenue requirement?

A. We developed the revenue requirement based on PGE's 2023 budgets, which were originally based on a 2022 budget that reflected our best estimate of PGE's 2022 general rate case result as approved in Commission Order No. 22-129. The 2023 budgets were escalated for inflation to 2024 and adjusted for known and measurable changes.

Q. How did you escalate the 2023 budget to the 2024 test year?

A. We applied the following escalation rates to the 2023 budget:

- 3.56% average rate for all labor (at applicable effective dates);[5]
- 3.84% for contract labor and outside services (cost elements [CE] 1502, 1602, 2200, and 2300), effective January 1;
- 0.0% for direct materials (CE 2101 and 2110), effective January 1; and
- 1.87% 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 *IHS Markit*, Long-term Forecast dated August 2022. While on average the *IHS Markit*, Long-term Forecast dated November 2022 has higher escalation rates than those provided in the August Forecast, PGE has made the decision not to increase its escalation rates further. Wage escalation is based on the forecast of compensation costs as described in PGE Exhibit 500.

Q. In explaining cost changes for test year 2024, what base year does PGE generally reference?

A. In the testimonies that discuss O&M, Customer Service, and Administrative and General (A&G) costs, we compare our 2024 test year forecast to the 2022 base year. We do this because 2022 represents PGE's most recent full year with actual results. The changes between 2022 and 2024 in this filing will be analyzed on an average annual basis.

[5] March 1 for bargaining employees and February 1 for non-bargaining employees.

Q. Did you adjust PGE's 2024 revenue requirement to reflect previous rate case decisions and other regulatory policies?

A. Yes. We made several regulatory adjustments, listed in Table 2 below.

Table 2
Regulatory Adjustments
($millions)

Category	**O&M**	**Rate Base**
Retail Services	$ (0.4)	$ (1.5)
Charitable Contributions	(2.2)	
State & Federal Lobbying	(1.4)	
MDCP	(4.3)	
SERP	(1.1)	
Image Advertising	(0.02)	
Total Adjustments*	**$ (9.5)**	**$ (1.5)**

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 $2.2 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 $4.3 million from cost of service;
- Supplemental Executive Retirement Plan (SERP): removed the entire $1.1 million from cost of service; and
- Corporate image advertising: removed the entire $0.02 million from cost of service.

II. Other Revenue

Q. What is PGE's 2024 forecast of Other Revenue?

A. PGE forecasts 2024 Other Revenue of $39.7 million. This compares to actual 2022 Other Revenue of $42.2 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 2024 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.

Q. Does your forecast of Other Revenue reflect the change to PGE's open access transmission tariff (OATT) rate or associated third-party transmission revenue?

A. Yes. PGE filed a transmission rate case (TRC) with the Federal Energy Regulatory Commission (FERC) in 2021. PGE has since reached a settlement on all issues in that case resulting in a transmission rate increase. Based upon the settlement reached, PGE filed an interim OATT rate filing for 2023 that results in settled rates effective prior to and pending the final order from the FERC. As such, PGE's 2024 forecast of transmission Other Revenues reflects these new rates.

Q. If transmission revenue is increasing, why do Other Revenues show a decrease from 2022 actuals to the 2024 forecast?

A. The appearance of a decrease in Other Revenues as compared to 2022 is due to three reasons:

1) Certain revenue being recorded to Other Revenue in 2020 through 2022 offsets expenses PGE incurred during the same period to provide project support for a third-party accessing PGE equipment. As both the costs and revenues associated with this project support are temporary and uncertain, neither have been forecast for 2024.
2) One of PGE's steam customers suffered a mechanical failure to their on-site boiler in 2022. This resulted in greater than normal 2022 steam sales revenue until the steam customer's boiler was returned to service in the fall of 2022.
3) PGE's transmission revenue actuals for 2022 include reimbursements from transmission intertie customers that compensate PGE for real power losses incurred in the provision of transmission service to these customers. As the cost of providing for real power losses to transmission intertie customers is not included in PGE's Net Variable Power Cost (NVPC) forecast used to establish cost-of-service prices, we remove the reimbursement revenues from our forecast for 2024.

Additionally, the portion of major maintenance accrual amounts recorded as other revenue flips from a debit amount to a credit amount from 2022 to 2024, due to the timing of when major work is performed against the timing of collections.

After normalizing for the items above, PGE's 2024 other revenue forecast increased approximately \$3.4 million compared to 2022 actuals and approximately \$5.5 million over the average of 2020 through 2022 actuals.

III. Depreciation

Q. What is the basis for the 2024 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, 2023, we used depreciation through this date in the calculation of all four items.

Q. Does this depreciation accurately reflect the 2024 expense?

A. By itself, no. Because this depreciation will only reflect partial year depreciation for 2023 plant closings,[6] that depreciation will be less than full 2024 depreciation, which will reflect a full year of depreciation for those same assets. To adjust for this effect, PGE annualized the 2023 depreciation expense for 2023 plant closings and then reduced that amount to account for the annualized effect of declining depreciable base in prior vintages. In summary, the 2023 depreciation expense is annualized and adjusted so that PGE does not under or over collect depreciation expense relative to expected 2024 depreciation expense. For simplicity, we refer to the test year depreciation as 2024 depreciation expense.

Q. What is PGE's estimate for 2024 depreciation expense?

A. We estimate $339.6 million in depreciation expense for 2024. PGE Exhibit 203 summarizes the 2024 depreciation expense by plant type and provides a comparison to 2022 actuals.

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

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, PGE does propose the following specific changes to depreciation rates:

- PGE proposes to extend the depreciable life for the Faraday hydro plant, including the new Faraday Units 7 and 8, beyond their current FERC license expiration date to 2085. We make this change because the new Faraday Units 7 and 8, which are replacing assets over 100 years old, effectively represent a new hydro plant. Therefore, it is expected that the life of these new assets will extend beyond the period of PGE's current FERC license. PGE Exhibit 800 provides extensive detail regarding this project.
- A new three-year amortization schedule for certain shorter-lived software intangible assets. The use of a three-year schedule is consistent with common utility practice for shorter-lived intangibles and amounts to approximately $1.2 million 2024 forecasted amortization expense.

Q. How does PGE's 2024 depreciation expense forecast compare to 2022 actuals?

A. After adjustments, total forecasted depreciation for 2024 reflects a $26.8 million increase over 2022 actuals.

Q. What are the primary drivers for the increase?

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

- $16.2 million for transmission and distribution facilities;
- $4.3 million for hydro facilities, due primarily to the Faraday Resiliency and Repowering Project;
- $3.3 million for Beaver generation plant due to the Beaver modernization project;
- $3.7 million in general plant; and
- $0.1 million in Coyote Springs generation plant.
- These increases are partially offset by:
- $0.6 million net reduction in wind and other generation plant.

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 2024 test year amortization expense similar to depreciation.

Q. Please summarize PGE's 2024 amortization expense.

A. PGE Exhibit 204 details the total 2024 amortization expense of $82.9 million, which we summarize in Table 3 below.

Table 3
Amortization Expense
($millions)

Category	2022 Actuals	2024 Forecast
Software Amortization 3-10 years	$56.6	$78.3
Other Intangible Amortization	3.5	3.5
Trojan Decommissioning	1.9	1.9
Regulatory Credits		(0.5)
Retail Allocation		(0.2)
Total Amortization*	$62.0	$82.9

* 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 2024 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.

Q. Please explain the amortization of software included in PGE's 2024 amortization expense.

A. Total software amortization is approximately $78.3 million. This cost relates to capitalized software, which is typically amortized over either a 5-year or 10-year period for larger software programs, such as PGE's customer information and meter data management systems. Additionally, as mentioned above, PGE has also incorporated a 3-year period for certain shorter lived software assets.

Q. Why is software amortization approximately $21.7 million higher in 2024 compared to 2022?

A. The increase is due to a number of items. First, there was a net decrease in software amortization in 2021 and 2022 compared to 2020 due to the roll-off of software investment in 2021, which was partially offset by software investment that closed to plant during 2020. Then, for 2024 there is an increase due primarily to PGE's Enterprise Resource Planning (ERP) and Customer to Meter (C2M) software investments, which are both forecast to close to plant prior to the end of 2023, increasing PGE's overall amortization expense. PGE Exhibit 600 provides more details regarding these major software investments.

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. Not at this time. We performed an analysis of the annual accrual, updated for the latest Trojan NDT balances, expected rate of return on trust assets, cost estimates, expected Department of Energy (DOE) reimbursements, and other parameters. This analysis indicates 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.

Q. What decommissioning activities are planned at Trojan in the future?

A. The only ongoing decommissioning work is storage of the spent nuclear fuel. There are no planned activities after the spent nuclear fuel has been removed from the site. The majority of structures at the facility have already been demolished. PGE completed the decommissioning and demolition of the Trojan North and Trojan Training buildings in 2014. Additionally, PGE is in the process of replacing the current administration building at the site with a new facility to house existing staff. This facility will not be placed into PGE's regulated rate base but will be recognized as a settlement against PGE's asset retirement obligation, with most of the cost expected to be reimbursed from the DOE.

Q. Are any Trojan-related funds currently being refunded to customers?

A. Yes. Pursuant to the UE 394 Fourth Partial Stipulation, which was adopted through Commission Order No. 22-129, PGE began refunding certain amounts related to DOE reimbursements through Schedule 143 over a one-year period beginning in the middle of 2022. As such, PGE expects to reset this schedule to $0 in the middle part of 2023, following the extinguishment of these amounts, and has no further expectation of additional refund amounts at this time.

V. Income Taxes and Taxes Other Than Income

A. Income Taxes

Q. What is PGE's 2024 estimate of income taxes?

A. PGE's 2024 test year forecast for income tax expense is $108.8 million. This compares to the 2022 utility income tax expense of $90.3 million based on prices approved by Commission Order No. 22-129 in UE 394. PGE Exhibit 205 provides details on the test year calculations of income tax expense plus a comparison to previously authorized 2022 income tax assumptions.

Q. What method did you use to establish estimated income tax expense for the 2024 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 and Multnomah County.[7]

[7] 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 2024 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 7.562%. 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. Why do you include the State of Montana marginal tax rate in your calculation now that nearly all Colstrip-related costs are included in Schedule 146?

A. While PGE does create a separate revenue requirement for collecting all costs related to the Colstrip plant, leaving a very limited amount of Montana-related costs in base rates, the same state composite tax rate is used for both Schedule 146 and base rates. As such, PGE will continue to calculate all revenue sensitive costs in Schedule 146, including taxes, consistent with the approved rates from PGE's most recent general rate case.

Q. Did you include the Oregon Corporate Activities Tax (OCAT) in your 2024 test year revenue requirement?

A. Yes. We have included the OCAT in this GRC as a separate line item within the revenue requirement, which we include within Taxes Other Than Income and discuss below.

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

A. PGE's total composite tax rate for this filing is 26.974%, 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:

$$21.00\% + 7.562\% - (21.00\% * 7.562\%) = 26.974\%$$

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 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 2024?

A. Yes. PGE has applied the following items (treated similar to tax credits) in accordance with Commission Order No. 18-464:

- 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."[8]
- A federal credit of approximately $10.3 million to reflect the average rate assumption method (ARAM) of amortizing excess deferred federal income taxes (EDIT).[9]

Q. Have any changes occurred since PGE's last GRC regarding its treatment of EDIT?

A. Yes. Based on a series of private letter rulings from the IRS since the filing of PGE's last general rate case (UE 394), PGE determined a change to the treatment of EDIT is required to avoid a potential violation of IRS tax normalization requirements. Specifically, this change

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[8] Commission Order No. 18-464, page 5 of Appendix D, item 4.
[9] Commission Order No. 18-464, page 4 of Appendix D, item 2.f.

requires PGE to treat separately the Cost of Removal (COR) component currently included within the EDIT balance. While both the Life and Salvage components of book depreciation are required by the IRS to be reversed over the life of the asset that gave rise to the EDIT, the IRS has ruled that the COR component, which PGE has previously been including within ARAM, should be separated.

As such, in order to comply with these recent IRS rulings, PGE must separate the COR EDIT from the Life/Salvage EDIT and reverse them using different methods. Should PGE fail to separate this component we could be found in violation of normalization rules, putting PGE’s ability to utilize accelerated depreciation at risk, which would adversely impact customer prices. Thus, PGE has separated the COR reversal component from the Life/Salvage EDIT and is proposing to reverse it over 50 years beginning in 2024. A 50-year life was chosen instead of a shorter average remaining book life to reduce the customer impact related to this item.

Q. How does this impact PGE’s estimate of income tax expense for 2024?

A. The separate COR reversal component represents a debit amount (i.e., increase to tax expense) of $1.9 million.

Q. Did you include any Production Tax Credits (PTCs) in your estimate of income tax expense for 2022?

A. Not in this filing. Consistent with the provisions of Oregon Senate Bill 1547, Section 18b, Federal PTCs are incorporated into PGE’s NVPC. Consequently, PGE’s test year PTCs are thus reflected in its Annual Update Tariff (AUT) filing.

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 (see pages 7 and 8).

B. Taxes Other than Income

Q. What is PGE's 2024 estimate of Taxes Other Than Income?

A. As shown in PGE Exhibit 206, total Taxes Other Than Income are $192.6 million for 2024. This compares to 2022 actual costs of $158.0 million. The primary cost changes from 2022 actuals to the 2024 test year are:

- Property Taxes: from $76.2 million to $90.1 million;
- Franchise Fees: from $52.6 million to $68.5 million;
- Payroll Taxes: from $18.0 million to $21.0 million; and
- OCAT: from $8.7 million to $10.4 million.

1. Property Taxes

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

A. PGE owns property in three states: Oregon, Montana (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 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. Why is PGE still including a Montana property tax amount if Colstrip is collected within Schedule 146?

A. While amounts associated with the Colstrip plant (including property and other taxes) are included in Schedule 146, amounts related to Colstrip transmission assets are still included within base rates and are not subject to accelerated depreciation. The property tax amount associated with these assets is approximately $0.7 million for 2024.

Q. What is PGE's forecast for 2024 property tax expense?

A. PGE has forecast approximately $90.1 million of 2024 property taxes compared to 2022 actuals of $76.2 million.

Q. Why are property taxes increasing from 2022 to the 2024 test year?

A. Oregon property tax expense increases by approximately $14.2 million due to an increase in net plant assets and additional construction work in progress (CWIP) balances that will be assessed property tax expense, including the Faraday Repower Project, and substantial investment in PGE's distribution system. Additionally, the SIP property tax abatement agreement for Biglow reached the end of its 15-year life in 2022, meaning the entirety of that site returns to regular property tax rates beginning in 2023. This is slightly offset by a decrease in Washington property taxes of approximately $0.3 million, due to decreases in net plant assets.

2. Franchise Fees

Q. Why have franchise fees increased from 2022 to the 2024 test year?

A. PGE updated the franchise fee rate to reflect the three-year average of 2019-2021 actuals. Although this represents a minimal increase in the franchise fee rate from 2.556% in 2022 (UE 394) to 2.565% in 2024, overall, franchise fees increase because they are a function of PGE's requested revenue requirement, which also increases.

3. Payroll Taxes

Q. How does PGE estimate payroll taxes?

A. PGE estimates payroll taxes by applying an approximate 8.9% 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 2022 to the 2024 test year?

A. Payroll taxes increase as wages and salaries grow between these years as described in PGE Exhibit 500.

Q. Are there additional reasons beyond PGE's growth in wages and salaries that are causing an increase to payroll taxes?

A. Yes. On January 1, 2023, all Oregon businesses with more than 25 employees in the state began paying a tax to support the Paid Leave Oregon program. PGE's portion of the tax burden amounts to 40% of 1% of total wages, or approximately 0.4% of the 8.9% noted above.

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, 2023, and forecasts the total balance to be approximately $6,290.5 million. 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 394?

A. PGE Exhibit 208 shows that the rate base approved in UE 394 is $5,432.0 million and that PGE's December 31, 2023 rate base reflects an increase of $858.5 million. The increase is primarily attributable to the growth in distribution plant as discussed in PGE Exhibit 700, the Faraday Repower Project as discussed in PGE Exhibit 800, and major software investments as discussed in PGE Exhibit 600.

Q. What is the Working Cash total added to rate base in this filing?

A. PGE has updated its lead/lag study to determine the Working Cash factor for use in calculating PGE's Working Cash total in rate base. This analysis results in the Working Cash factor increasing from 3.891% in 2022 (UE 394) to 4.222% in 2024. Applying the 4.222% Working Cash factor to total forecasted operating expenses in 2024 of $2,267.2 million produces the Working Cash total in rate base of approximately $95.7 million.

Q. Is PGE proposing to include any new amounts within rate base?

A. Yes. PGE is proposing to treat a portion of cloud-based vendor hosted software as a rate base asset (i.e., Miscellaneous Deferred Debits). This software is similar to the on-premise software that PGE routinely capitalizes and includes within software amortization expense, with the primary difference being where the software is housed. Cloud-based software solutions offer numerous advantages to traditional on-premise software. However, current accounting guidelines have not kept pace with this rapidly changing technology, creating an inherent utility disincentive towards investing in cloud-based vendor hosted software. In order to reflect and account for the shift in software hosting, while correcting for an imbalance of incentives and unnecessary complexity when considering what IT software solution is best for PGE and customers, we are proposing to include in rate base license fees and hosting fees related to cloud-based software under three-, five-, and ten-year contracts, that otherwise should be included within the calculation of PGE's Working Cash.

Q. Does PGE also propose including a corresponding amount within its amortization expense?

A. No. Rather than include annual expense amounts in FERC account 404 (Amortization of limited-term electric plant), PGE proposes to treat the annual expense portion of these contracts the same as we have previously treated them. That is, PGE will continue to reflect the annual portion of the contract as IT-related expense included within the Operations and Maintenance expense accounts corresponding to the functional use of the underlying software (e.g., Administrative and General expense accounts, Customer Services expense accounts, Generation expense accounts, etc.), while reflecting the net amount remaining in the contract as a rate base asset. PGE Exhibit 600, Section III discusses this proposed mechanism in greater detail.

Q. Has PGE made any adjustment to rate base?

A. Yes. Consistent with our treatment in UE 394, PGE has continued 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. Please discuss how you apply Allowance for Funds Used During Construction (AFUDC).

A. As capital projects are being constructed, their costs are recorded in 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 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 or cancelled.

VII. Unbundling

Q. Have you unbundled the 2024 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 4 below summarizes the base unbundled revenue requirement for 2024.

Table 4
Unbundled Revenue Requirement
($millions)

Production	$ 1,470.7
Transmission	121.5
Distribution	867.4
Ancillary	8.5
Metering	3.4
Billing	47.2
Other Consumer Services	153.6
Total*	**$ 2,671.5**

** 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 3.

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 2024 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 4 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.

VIII. 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.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	Description
201	2024 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	2024 Unbundled Results of Operations Summary

PGE
UE 416
Exhibit 201
Increase in Base Rates Needed for Reasonable Return
Scaled (Thousands)

Line No.		Base Rate	Change for Resonable Return	Results after Change for Reasonable Return
		(1)	(2)	(3)
1		Base Business		14.47%
2				
3	Sales to Consumers (Rev. Req.)	2,333,738	337,807	2,671,545
4	Other Revenue Detail	39,681	-	39,681
5	Total Operating Revenue	2,373,419	337,807	2,711,226
6				
7	Operation & Maintenance			
8	Net Variable Power Cost	860,056	-	860,056
9	Production O&M	103,545	-	103,545
10	Power Operations	30,422	-	30,422
11	Trojan O&M	65	-	65
12	Transmission O&M	22,409	-	22,409
13	Distribution O&M	209,780	-	209,780
14	Operations O&M	366,221		366,221
15	Customer Accounts	61,968	-	61,968
16	Customer Service	31,862	-	31,862
17	Uncollectibles Expense	11,669	1,689	13,358
18	OPUC Fees	11,043	1,598	12,641
19	A&G, Ins/Bene., & Gen. Plant	197,185	-	197,185
20	Support O&M	313,727	3,287	317,014
21	Total Operating & Maintenance	1,540,004	3,287	1,543,291
22				
23	Depreciation	339,638	-	339,638
24	Amortization	82,937	-	82,937
25	Property Tax	90,128	-	90,128
26	Payroll Tax	21,000	-	21,000
27	Other Taxes	2,542	-	2,542
28	Oregon CAT	10,370	-	10,370
29	Franchise Fees	59,863	8,665	68,528
30	Utility Income Tax	20,904	87,871	108,776
31	Total Operating Expenses & TOTI	2,167,387	99,824	2,267,211
32				
33	Utility Operating Income	206,032	237,983	444,014
34				
35	**Rate of Return**	3.277%		7.059%

PGE
UE 416
Exhibit 201
Increase in Base Rates Needed for Reasonable Return
Scaled (Thousands)

Line No.		Base Rate	Change for Resonable Return	Results after Change for Reasonable Return
36	*Weighted Cost of Debt*	2.159%	2.159%	2.159%
37	*Weighted Cost of Preferred*			
38	*Equity Share of Cap Structure*	50.000%	50.000%	50.000%
39	**Return on Equity**	2.238%		9.800%
40				
41	**Rate Base**			
42	Gross Plant	12,249,545	-	12,249,545
43	Accum. Deprec. / Amort	(5,441,309)	-	(5,441,309)
44	Accum. Def Tax	(667,288)	-	(667,288)
45	Net Utility Plant	6,140,947		6,140,947
46				
47	Operating Materials & Fuel	91,228	-	91,228
48	Misc. Deferred Credits	(55,231)	-	(55,231)
49	Misc. Deferred Debits	17,829	-	17,829
50	Working Cash	91,505	4,214	95,720
51	Total Rate Base	6,286,279	4,214	6,290,494
52				
53	Income Tax Calculations			
54	Book Revenues	2,373,419	337,807	2,711,226
55	Book Expenses	2,146,483	11,953	2,158,436
56	Interest Expense	135,689	91	135,780
57	Permanent M Differences	(17,632)	-	(17,632)
58	Temporary Sch M Differences	44,542	-	44,542
59	State Taxable Income	64,336	325,763	390,100
60				
61	State Income Tax	4,855	24,634	29,490
62				
63	Federal Taxable Income	59,481	301,129	360,610
64				
65	Federal Tax	12,491	63,237	75,728
66				
67	Deferred Taxes	12,015	-	12,015
68	Excess Deferred Income Tax Reversal (ARAM)	(10,316)	-	(10,316)
69	Excess Cost of Removal (COR) Reversal	1,859	-	1,859
70	Total Income Tax	20,904	87,871	108,776

PGE
UE 416
Exhibit 201
Capital Structure / Revenue Sensitive Costs
Not Scaled

Line No.	Rates	Dec - 2024
1	% R&D per UE 335	0.9097%
2	California State Income Tax - Appor	3.9117%
3	California State Income Tax - Rate	8.8400%
4	California State Income Tax - Weighted	0.3458%
5	Common Equity - Cost	9.8000%
6	Common Equity - Share	50.0000%
7	Common Equity - Weighted	4.9000%
8	Composite Tax Rate	26.974015%
9	Factor per OAR	0.1250%
10	Fed Tax	21.0000%
11	Federal Tax @ 21.000%	18.7251%
12	Federal Taxable Inc.	89.1672%
13	Franchise Fees	2.5651%
14	Gross-Up Factor	1.3694
15	Long-Term Debt - Cost	4.317%
16	Long-Term Debt - Share	50.000%
17	Long-Term Debt - Weighted	2.159%
18	Montana State Income Tax - Appor	2.3229%
19	Montana State Income Tax - Rate	6.7500%
20	Montana State Income Tax - Weighted	0.1568%
21	Net To Gross Factor	141.9605%
22	O&M Uncollectibles	0.5000%
23	OPUC Fees	0.4732%
24	Oregon Benefit of Local Tax deduction	(0.0017%)
25	Oregon State Income Tax - Appor	92.6087%
26	Oregon State Income Tax - Rate	7.6000%
27	Oregon State Income Tax - Weighted	7.0383%
28	Portland Local Income Tax - Appor	0.8822%
29	Portland Local Income Tax - Rate	2.6000%
30	Portland Local Income Tax - Weighted Plus Benefit	0.0212%
31	Portland Local Income Tax - Weighted Pre Benefit	(0.0229%)
32	Revenues	100.0000%
33	RSC Gross-Up Factor	1.0367
34	State and Local Tax @ Present Rate	7.2945%
35	State and Local Tax Rate - Weighted	7.5620%
36	State Taxable Income	96.4617%
37	Tax Shield	(1.5880%)
38	Total Income Taxes	26.0196%

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UE 416
Exhibit 201
Capital Structure / Revenue Sensitive Costs
Not Scaled

Line No.	Rates	Dec - 2024
39	Total Rev. Sensitive Costs	29.5579%
40	Utility Operating Income	70.4421%
41	Working Cash Factor	4.2219%
42	Capital Structure Total	7.059%

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UE 416
Exhibit 202
Other Revenue Detail
Not Scaled

Line No.	Account	a-Dec - 2020	a-Dec - 2021	a-Dec - 2022	Dec - 2023	Dec - 2024
1	4470003: SalesfrResale-IntertiePGEtoPGE	(7,067,265)	-	-	-	-
2	4500001: Forefeited Discounts	(1,510,490)	(1,384,370)	(2,462,939)	(1,756,856)	(1,954,385)
3	4510001: Miscellaneous Service Revenues	(917,276)	(629,537)	(874,209)	(1,341,679)	(1,868,962)
4	4530001: Sales of Water & Water Power	20,340	6,587	25,917	-	-
5	4540001: Rent From Electric Property	(1,453,820)	(1,535,450)	(1,457,150)	(1,309,499)	(1,309,499)
6	4540002: RentFrElecProperty-Joint Pole	(12,375,540)	(14,224,820)	(14,254,253)	(14,524,137)	(14,524,137)
7	4560001: Other Electric Revenues	(6,811,407)	(6,595,414)	(6,174,115)	(1,346,051)	(1,346,051)
8	4560002: OthElecRev-RegulatoryDeferRev	3,381,845	2,374,347	1,962,199	(9,085,617)	(1,461,881)
9	4560003: OthElecRev-FishWildlifeRecrOps	(16,397)	(12,590)	(14,115)	(20,063)	(17,569)
10	4560005: OthElecRev-Utility Non-Kwh	(22,251)	(32,509)	(25,254)	-	-
11	4560012: OthElecRev-Steam Sales	(1,419,239)	(2,562,812)	(5,059,402)	(2,300,000)	(2,300,000)
12	4561001: TransRevOthers-Non-Intertie	(3,659,943)	(3,826,701)	(82,263)	-	-
13	4561002: TransRevOthers-Intertie	(6,945,362)	(7,375,517)	(64,794)	-	-
14	4561004: Trans Network Services	-	-	(5,518,169)	-	-
15	4561005: Trans Long Term Firm	-	-	(11,377,573)	-	-
16	4561006: Trans Short Term Firm	-	-	(374)	-	-
17	4561007: Trans Short Term Non-Firm	-	-	(662,425)	-	-
18	4561008: Trans Other Services	-	-	3,883,829	(9,255,240)	(14,898,324)
19	5660002: TransOp-MiscExp-IntertieWhePGE	7,067,265	-	-	-	-
20	Total	(31,729,540)	(35,798,788)	(42,155,091)	(40,939,141)	(39,680,807)

PGE
UE 416
Exhibit 203
Depreciation Detail
Scaled (Thousands)

Line No.	Property Group	a-Dec - 2020	a-Dec - 2021	a-Dec - 2022	Dec - 2023	Dec - 2024
		(1)	(2)	(3)	(4)	(5)
1	Beaver	7,142	7,177	7,660	9,015	10,943
2	Biglow Canyon	30,315	29,019	29,801	29,428	29,808
3	Carty	12,404	12,292	12,286	12,186	12,229
4	Coyote Springs	4,775	4,578	4,432	4,560	4,580
5	DSG	348	340	352	349	342
6	Port Westward	7,959	7,745	7,564	7,347	7,352
7	Port Westward 2	7,308	7,225	8,122	7,752	7,777
8	Solar	142	51	36	90	79
9	Tucannon	14,771	14,315	14,900	14,899	15,155
10	Wheatridge		5,525	5,490	5,387	5,170
11	Hydro	22,253	22,417	20,705	27,188	24,959
12	Transmission	17,912	21,067	22,505	24,532	25,204
13	Distribution	120,970	132,840	130,059	131,284	143,569
14	General Plant	40,786	41,480	48,884	49,187	52,625
15	**Total**	**287,086**	**306,072**	**312,795**	**323,204**	**339,793**
16	Remove Boardman Decommissioning	(3,851)	-	-	-	-
17	Retail Adjustment	-	-	-	-	(155)
18	**Adjusted Total**	**283,235**	**306,072**	**312,795**	**323,204**	**339,638**

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UE 416
Exhibit 204
Amortization Detail
Scaled (Thousands)

Line No.	Item	FERC Account	a-Dec - 2020	a-Dec - 2021	a-Dec - 2022	Dec - 2023	Dec - 2024
			(1)	(2)	(3)	(4)	(5)
1	Software Amortization (Intangible)	404	56,843	54,204	56,615	62,688	78,292
2	Other Intangible Plant (Includes Hydro Relicensing)	404	5,813	3,778	3,486	3,490	3,521
3	Amort Of UnrecvPlt-Troj Decomm	407	1,900	1,900	1,900	1,900	1,900
41	Regulatory Credits - Incentive Adjustment	407.4	-	-	-	-	(500)
46	Regulatory Credits - SunWay 3	407.4	(45)	(45)	(45)	(45)	(45)
47			64,511	59,836	61,955	68,033	83,167
48	Allocated to Retail		-	-	-	-	(230)
49		Total	**64,511**	**59,836**	**61,955**	**68,033**	**82,937**

PGE
UE 416
Exhibit 205
Income Tax Summary
Scaled (Thousands)

Line No.	Line	UE 394 2022 Test Year		Proposed: Proposed
1	Book Revenues	2,066,366		2,711,226
2	Book Expenses (including Depreciation)	1,605,983		2,158,436
3	Interest Deduction	112,034		135,780
4	Book Taxable Income	348,349		417,010
5	Production Deduction			
6	Permanent Sch. M	(13,414)		(17,632)
7	Temporary Sch. M	133,129		44,542
8	Taxable Income	228,634		390,100
9				
10	Current State Taxes	17,363		29,500
11	State Tax Credits	(10)		(10)
12	Net State Income Tax	17,353		29,490
13				
14	Federal Taxable Income	211,281		360,610
15				
16	Current Federal Taxes	44,369		75,728
17				
18	Federal Tax Credits			
19	ITC Amortization	(7,335)		(8,457)
20	Deferred Taxes	35,944		12,015
21				
22	Total Income Tax	90,331		108,776
23	Effective Tax Rate	25.93%		26.08%
24	Regulated Net Income			308,234
	Change in Taxes			18,445
	Analysis of Tax Change:			
	Effective Tax Rate Change			0.15%
	Book Taxable Income (Last Rate Case)			348,349
	Decrease in Taxes Due to Lower Effective Rate			535
	Change in Book Taxable Income (Current vs Last Rate Case)			68,661
	2024 Effective Tax Rate			26.08%
	Decrease in Taxes Due to Lower Book Taxable Income			17,910
	Sum of Tax Impacts			18,445

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UE 416
Exhibit 206
Taxes Other Than Income
Not Scaled

Line No.	Item	FERC	Account	a-Dec - 2020	a-Dec - 2021	a-Dec - 2022	Dec - 2023
1	Payroll Taxes	408.1	4081004: Payroll Taxes - FICA	24,636,475	27,194,747	27,833,943	32,221,531
2	Payroll Taxes	408.1	4081005: Payroll Taxes - Fed Unemploy	66,998	139,699	139,841	131,919
3	Payroll Taxes	408.1	4081006: Payroll Taxes - Trimet	2,120,589	2,114,912	2,334,323	2,366,054
4	Payroll Taxes	408.1	4081007: Payroll Taxes - State Umemploy	1,428,468	1,953,563	3,433,917	3,640,531
5	Payroll Taxes	408.1	4081008: Payroll Taxes - Worker's Comp	403,597	279,369	330,051	-
6	Payroll Taxes	408.1	4081009: AllocCredit - Payroll Tax	(14,711,133)	(15,059,038)	(16,110,505)	(18,168,011)
7	Property Taxes - Oregon	408.1	4081001: TaxOthThan IncTax-PropTax-Oreg	65,155,885	68,983,883	73,151,107	78,985,443
8	Property Taxes - Washington	408.1	4081002: TaxOthThan IncTax-PropTax-Wash	2,220,400	2,068,163	2,427,170	2,131,224
9	Property Taxes - Montana	408.1	4081003: TaxOthThan IncTax-PropTax-MT	804,665	703,523	667,579	678,604
10	Franchise Fees	408.1	4081010: TaxOthThanIncTax-FranFeePort	14,554,423	15,329,433	16,244,806	17,460,643
11	Franchise Fees	408.1	4081011: TaxOthThanIncTax-FranFeeOthCit	31,484,054	32,942,514	36,314,842	38,660,429
12	Foreign Insurance Excise Tax	408.1	4081012: TaxOthThanIncTx-ForInsrExcisTx	-	70,826	6,093	-
13	Misc. Tax & Lic Fees - Oregon	408.1	4081013: TaxOthThanIncTx-MiscTax&Lic-OR	2,076,210	2,377,602	2,535,464	2,542,329
14	Oregon CAT	409.1_OTHER	4091230: OR Corp Activity Tax-Utility	7,471,429	8,328,745	8,727,970	9,602,126
				137,712,060	147,427,942	158,036,601	170,252,822

PGE
UE 416
Exhibit 206
Taxes Other Than Income
Not Scaled

Line No.	Item	FERC	Account	Dec - 2024
1	Payroll Taxes	408.1	4081004: Payroll Taxes - FICA	32,943,143
2	Payroll Taxes	408.1	4081005: Payroll Taxes - Fed Unemploy	148,322
3	Payroll Taxes	408.1	4081006: Payroll Taxes - Trimet	2,634,807
4	Payroll Taxes	408.1	4081007: Payroll Taxes - State Umemploy	3,883,266
5	Payroll Taxes	408.1	4081008: Payroll Taxes - Worker's Comp	-
6	Payroll Taxes	408.1	4081009: AllocCredit - Payroll Tax	(18,609,287)
7	Property Taxes - Oregon	408.1	4081001: TaxOthThan IncTax-PropTax-Oreg	87,318,635
8	Property Taxes - Washington	408.1	4081002: TaxOthThan IncTax-PropTax-Wash	2,131,224
9	Property Taxes - Montana	408.1	4081003: TaxOthThan IncTax-PropTax-MT	678,604
10	Franchise Fees	408.1	4081010: TaxOthThanIncTax-FranFeePort	68,527,934
11	Franchise Fees	408.1	4081011: TaxOthThanIncTax-FranFeeOthCit	-
12	Foreign Insurance Excise Tax	408.1	4081012: TaxOthThanIncTx-ForInsrExcisTx	-
13	Misc. Tax & Lic Fees - Oregon	408.1	4081013: TaxOthThanIncTx-MiscTax&Lic-OR	2,542,329
14	Oregon CAT	409.1_OTHER	4091230: OR Corp Activity Tax-Utility	10,370,296
				192,569,272

PGE
UE 416
Exhibit 207
Rate Base
Scaled (Thousands)

Line No.	Line	Based on Ending Balances
1	Plant in Service	12,249,545
2	Less: Accumulated Depreciation/Amortization	(5,441,309)
3	Accumulated Deferred Taxes	(667,288)
4	Accumulated Deferred ITC	
5		
6	**Net Utility Plant**	6,140,947
7		
8	**Operating Materials and Fuel Stocks**	91,228
9		
10	**Deferred Debits**	
11	Glass Insulators	5,847
12	Major Maintenance Accruals	(1,871)
13	Cloud-Based License and Hosting Fees	8,227
14	Dispatchable Standby Generation	4,197
15	Wheatridge O&M Start-up Costs	1,429
16		
17	**Deferred Credits**	
18	Injuries & Damages	(8,240)
19	Customer Deposits	(10,973)
20	Incentive Adjustment (UE 283)	(5,500)
21	Post Retirement Liabilities	(29,804)
22	Misc. Other	(714)
23		
24		
25	**Working Capital**	95,720
26		
27	**Rate Base**	6,290,494

PGE
UE 416
Exhibit 208
Rate Base Comparison
Scaled (Thousands)

Line No.	Line	UE 394 Approved Order No. 22-129	Test Year at GRC Rates	2024 Variance to Approved
1	Plant in Service	10,951,085	12,249,545	1,298,460
2	Less: Accumulated Depreciation/Amortization	(4,887,187)	(5,441,309)	(554,122)
3	Accumulated Deferred Taxes	(690,748)	(667,288)	23,460
4	Accumulated Deferred ITC			
5				
6	**Net Utility Plant**	5,373,150	6,140,947	767,798
7				
8	**Operating Materials and Fuel Stocks**	55,799	91,228	35,429
9				
10	**Deferred Debits**			
11	Glass Insulators	5,477	5,847	369
12	Major Maintenance Accruals	(3,163)	(1,871)	1,293
13	Cloud-Based License and Hosting Fees		8,227	8,227
14	Dispatchable Standby Generation	7,069	4,197	(2,872)
15	Wheatridge O&M Start-up Costs	1,517	1,429	(88)
16				
17	**Deferred Credits**		-	
18	Injuries & Damages	(8,813)	(8,240)	573
19	Customer Deposits	(11,737)	(10,973)	765
20	Incentive Adjustment (UE 283)	(6,333)	(5,500)	833
21	Post Retirement Liabilities	(46,213)	(29,804)	16,409
22	Misc. Other	(790)	(714)	76
23				
24				
25	**Working Capital**	65,995	95,720	29,725
26				
27	**Rate Base**	5,431,958	6,290,494	858,536

PGE
UE 416
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	(43,837,475)
5	Gross-Up Factor	1.369
6	PTCs	(32,012,748)

PGE
UE 416
Exhibit 210
Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Other Production	NVPC	Transmission	Distribution	Ancillary	Billing	Metering	Consumer	Total
1	Operating Revenues									
2	Sales to Consumers (Rev. Req.)	603,326	867,399	121,526	866,686	8,450	47,194	3,381	153,583	2,671,545
3	Sales for Resale									
4	Other Revenue Detail	13,725		1,133	33,273	(8,450)				39,681
5	Total Operating Revenues	617,051	867,399	122,659	899,959	-	47,194	3,381	153,583	2,711,226
6										
7	Operation & Maintenance									
8	Net Variable Power Cost		860,056							860,056
9	Total Fixed O&M	137,393		18,983	209,780					366,156
10	Other O&M	61,220	4,104	10,892	101,320		34,254	1,229	104,061	317,079
11	Total Operating & Maintenance	198,613	864,161	29,874	311,100	-	34,254	1,229	104,061	1,543,291
12										
13	Depreciation & Amortization	158,317		27,500	202,681		5,555	349	28,173	422,575
14	Other Taxes / Franchise Fees	43,343		10,164	130,459		1,754	301	6,547	192,569
15	Utility Income Tax	40,214	661	10,808	52,595		1,143	292	3,063	108,776
16										
17	Total Oper. Expenses & Taxes	440,487	864,821	78,346	696,835	-	42,707	2,171	141,845	2,267,211
18										
19	Utility Operating Income	176,564	2,577	44,313	203,124	-	4,487	1,211	11,739	444,014
20										
21	Rate of Return	7.06%	7.06%	7.06%	7.06%		7.06%	7.06%	7.06%	7.06%
22										
23	Return on Equity	9.80%	9.80%	9.80%	9.80%	(4.32%)	9.80%	9.80%	9.80%	9.80%
24										
25										

PGE
UE 416
Exhibit 210
Unbundled Results of Operations Summary
Scaled (Thousands)

Line No.	Line	Other Production	NVPC	Transmission	Distribution	Ancillary	Billing	Metering	Consumer	Total
26	**Rate Base**									
27	Gross Plant	4,795,995		1,101,541	5,825,967		124,428	62,299	339,314	12,249,545
28	Accum. Deprec. / Amort	(1,950,624)		(413,846)	(2,811,325)		(58,319)	(43,710)	(163,485)	(5,441,309)
29	Accum. Def Tax	(420,737)		(68,155)	(163,839)		(3,182)	(1,427)	(9,948)	(667,288)
30										
31										
32	Net Utility Plant	2,424,634	-	619,539	2,850,803	-	62,927	17,163	165,881	6,140,947
33										
34	Operating Materials & Fuel	64,399		1,068	25,762					91,228
35	Misc. Deferred Debits	5,843		6,272	3,649		352	22	1,691	17,829
36	Misc. Deferred Credits	(12,036)		(2,389)	(31,914)		(1,512)	(124)	(7,256)	(55,231)
37	Working Cash	18,597	36,512	3,308	29,420		1,803	92	5,989	95,720
38										
39	Total Rate Base	2,501,437	36,512	627,797	2,877,720	-	63,571	17,152	166,304	6,290,494
40										
41	*Weighted Cost of Debt*	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%
42	*Equity Share of Cap Structure*	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
43	Excess Cost of Removal (COR) Reversal	1,222		162	428		10	4	33	1,859

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Net Variable Power Costs (NVPC)

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Erin Schwartz
Darrington Outama
Stefan Cristea

February 15, 2023

Table of Contents

I. Introduction

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

A. My name is Erin Schwartz. My position at PGE is Manager, Gross Margin and Power Cost Forecasting & Analysis.

My name is Darrington Outama. My position at PGE is Senior Director, Energy Supply.

My name is Stefan Cristea. My position at PGE is Regulatory Consultant, Regulatory Operations.

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 provide the initial forecast of PGE's 2024 Net Variable Power Costs (NVPC). We discuss proposed enhancements to MONET modeling, as well as other inputs. We compare our initial 2024 forecast with PGE's final 2023 NVPC forecast and explain why the per-unit expected NVPC have increased by approximately $5.0 per MWh.

Q. What is PGE's initial net variable power cost forecast

A. Our initial 2024 NVPC forecast is $860.1 million, based on contracts and forward curves as of December 31, 2022. This initial 2024 NVPC forecast represents an increase of approximately $129.8 million relative to our final 2023 NVPC forecast.

Q. Will PGE make a separate 2024 test year Annual Update Tariff (AUT) filing?

A. No. The NVPC portion of this general rate case establishes the basis for recovering these costs and will be the 2024 forecast to which we compare the 2024 actual NVPC pursuant to the provisions of Schedule 126, which implements the Power Cost Adjustment Mechanism (PCAM).

Q. Does PGE propose changes to the PCAM in this proceeding?

A. Yes. PGE describes the proposed PCAM changes and the basis for the proposal in PGE Exhibit 400.

Q. What are the primary factors that explain the increase in NVPC forecast for 2024 versus the NVPC forecast for 2023 in Docket No. UE 402?

A. The increase in NVPC is primarily driven by increased forward energy price curves and an expected increase to load compared to the final 2023 NVPC forecast. The impacts of the 2023 price curves and load increases are: 1) approximately $62.4 million due to increased forecast output from our thermal generation plants at a higher cost per unit, 2) approximately $39.6 million due to increased generation from power purchase agreements, reduced market sales and associated benefits, and increased market purchases, 3) approximately $14.3 million in costs associated with increased market purchases and reduced market sales due to an expected 72 MWa load increase in 2024, 4) approximately $9.3 million increase due to increased energy deliveries from hydro contracts, and 5) approximately $3.4 million in transmission costs related to reduced forecast benefits from using our transmission rights to transact at the California-Oregon Border (COB) market. Section V, Table 9 lists the above changes in NVPC by factor between 2023 and 2024.

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

A. No. PGE's 2024 revenue requirement does not include any costs or benefits related to the Clearwater Wind project (Clearwater). We are in the beginning stages of forecasting the annual expected costs and benefits of this project for ratemaking purposes and we expect to file a request under PGE's Schedule 122, Renewable Resources Automatic Adjustment

Clause, sometime during the third quarter of 2023 for the inclusion of Clearwater into customer prices consistent with the project being placed into service.

Q. Are there Minimum Filing Requirements (MFRs) associated with PGE's NVPC filings?

A. Yes. Public Utility Commission of Oregon (OPUC or Commission) Order No. 08-505 adopted a list of MFRs for PGE to follow in AUT filings and General Rate Case (GRC) filings. The MFRs define the documents that PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 301 contains the list of required documents as approved by Commission Order No. 08-505. The MFRs required for our initial filing are included as part of our electronic work papers, with the remainder of the MFRs to be submitted within 15 days of this filing (i.e., March 2, 2023). The MFR documents are designated as either "confidential" or "non-confidential."

Q. What timeframe do you propose for NVPC updates in this docket?

A. We propose the following schedule for our power cost update filings:

- April 1 – Update parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; California Carbon Allowance (CCA) forward price curve; Wheatridge renewable energy certificate (REC) monetization benefits, the Wheatridge facility performance report; and any errata corrections to our February 15 initial filing;

- July – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; CCA forward price curve; planned thermal and hydro maintenance outages; and loads;
- October – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; CCA forward price curve; planned hydro maintenance outages; and loads; and
- November – Two update filings: 1) update gas and electric forward curves; CCA forward price curve; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term customer opt-outs; Wheatridge REC monetization benefits; and 2) final update of gas and electric forward curves; final update to Qualifying Facilities commercial operation dates; and final update to the price of the power contract with Grant County.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II: MONET Model
- Section III: MONET Updates and Modeling Changes
- Section IV: Forthcoming Updates
- Section V: Comparison with 2023 NVPC Forecast; and
- Section VI: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2024?

A. As in prior dockets, we used our power cost forecasting model, called "MONET" (the Multi-area Optimization Network Energy Transaction model).

Q. Please briefly describe MONET.

A. We built this model in the mid-1990s and have since incorporated several refinements. Using data inputs, such as an hourly load forecast and forward electric and gas curves, the model minimizes power costs under "normal" conditions by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

- Retail load forecast, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, operating constraints, emissions control chemicals, and any variable operating and maintenance costs (although not part of NVPC for ratemaking purposes, except as discussed below);
- Hydroelectric plants, with output reflecting current non-power operating constraints (such as fish issues) and peak, annual, seasonal, and hourly maximum usage capabilities;
- Wind and solar power plants, with peak capacities, annual capacity factors, and monthly and hourly shaping factors;
- Transmission (wheeling) costs;

- Physical and financial electric contract purchases and sales; and
- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, MONET simulates the dispatch of PGE resources to meet customer loads based on the principle of economic dispatch; generally, any plant is dispatched when it is available and its dispatch cost is below the market electric price. Thermal plants can operate in one of various stages – maximum availability, ramping up to maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro and wind generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with hypothetical market purchases (or sales) priced at the forward market price curve.

Q. How does PGE define NVPC?

A. NVPC include wholesale (physical and financial) power purchases and sales (purchased power and sales for resale), fuel costs, and other costs that generally change as power output changes. PGE records its NVPC to Federal Energy Regulatory Commission (FERC) accounts 447, 501, 547, 555, and 565. As in the 2023 NVPC proceeding, we include certain variable chemical costs, lubricating oil costs, and forecasted federal production tax credits (PTCs). We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. Based on prior Commission decisions, certain fixed costs, such as excise taxes and transportation charges, are included in MONET. For the purposes of FERC accounting, these items are included with fuel costs in a balance sheet account for inventory (FERC 151); this inventory is then expensed to NVPC as fuel is consumed. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, transmission, natural gas, fuel, and associated financial instruments.

Q. Do the MFRs provide more detailed information regarding the inputs to MONET?

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop our initial forecast of 2024 NVPC.

III. MONET Updates and Modeling Changes

Q. Does PGE present both parameter updates and modeling enhancements in this initial filing?

A. Yes. We include the parameter revisions allowed under PGE's AUT (Tariff Schedule 125), as well as modeling enhancements and updates.

Q. What updates are currently allowed under PGE's Schedule 125, AUT Tariff?

A. Schedule 125 states that the following updates are allowed in AUT filings:

- Forced Outage Rates based on a four-year rolling average;
- Projected planned plant outages;
- Wind energy forecast based on a five-year rolling average;
- Costs associated with wind and solar integration. The battery portion of wind and solar projects that have a battery storage component may be included if the battery is charged solely by wind and solar generation;
- Dispatch of Energy Storage Systems;
- Forward market prices for both gas and electricity;
- Projected loads;
- Contracts for the purchase or sale of power and fuel;
- Emission control chemical costs;
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes;
- 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; and
- Projections of State and Federal Tax Credits.

Q. What MONET updates do you include in this GRC filing?

A. In this initial filing we include many of the Schedule 125 updates listed above. Additional items requiring actual 2022 data, or for which updated data were not available in a timely manner for this initial NVPC filing, will be updated in our April 1 filing. For example, among those items is the update to thermal forced outage rates. We plan to file an update that includes forced outage rates based on 2018 through 2022 data by April 1, 2023, consistent with information that would be used in an initial AUT filing for 2024. For this initial filing, we use the same forced outage rates, based on 2017 through 2021 data, from Docket No. UE 402 (UE 402). We will continue to update several of the items included under Schedule 125 as this docket proceeds.

Q. What modeling enhancements and new items do you include in this GRC filing?

A. We include thermal plant parameter updates and additional modeling enhancements and new items. In this testimony we discuss the following updates and modeling enhancements:

- Section III.A: Schedule 125 Guidelines Update
- Section III.B: Capacity Planning
- Section III.C: Washington Cap-and-Invest Program
- Section III.D: Gas Resale and Storage Modeling
- Section III.E: Other Items:
    1. 2024 Gas Physical Call Option
    2. California-Oregon Border (COB) Trading Margin Refinement
    3. Extended Day-Ahead Market (EDAM) Update

4. QF Pass-Through Mechanism

Q. Do you propose changes to Schedule 125 guidelines in this case?

A. Yes. We propose that modeling enhancements and updates be allowed under Schedule 125, irrespective of PGE filing a GRC. We provide detail and discuss why it is appropriate and necessary to allow modeling enhancements in AUT years in Section III.A.

Q. What is the net effect on PGE's initial 2024 NVPC forecast of the updates and modeling enhancements included in the initial MONET step-log?

A. The net effect of the updates and modeling enhancements reflected in the initial MONET step-log is an increase of $68.1 million in PGE's initial 2024 NVPC forecast from the base 2024 NVPC forecast.

Q. What load forecast does PGE use in this initial filing?

A. We use the 2024 retail load forecast described in PGE Exhibit 1100. Our forecast is approximately 21,063 thousand MWh of cost-of-service energy, or approximately 2,398 MWa, an increase of 72 MWa from the final 2023 test year forecast (Docket No. UE 402).

A. Schedule 125 Guidelines Update

Q. Please summarize your proposal with regard to the Schedule 125 guidelines.

A. We propose to modify the Schedule 125 guidelines to allow the application of NVPC forecast modeling enhancements in non-GRC years. The approval of this proposal will ensure that PGE has the modeling flexibility to address the increased operational challenges and market changes due to both new design, regulations, and fundamentals that we expect in future years and allow for a NVPC forecast that is as accurate as possible.

Q. When did the Commission adopt the Annual Update Tariff (AUT) and Schedule 125 guidelines?

A. The Commission adopted the AUT in Docket No. UE 180/UE 181/UE 184 (UE 180), through Order No. 07-015.[1] Subsequently, the Commission established MFRs in Docket No. UE 198 through Order No. 08-505.

Q. What was the Commission's guideline with regard to modeling enhancements when MFRs were established?

A. Commission Order No. 08-505 established that in either an AUT year or a GRC year, "at a minimum […] the Direct Case Filing MFRs will be delivered with the initial filing" and that "modeling enhancements and new item inputs" are not applicable in AUT years.[2] Therefore, PGE has not included modeling enhancements and new item inputs in AUT years, unless agreed to between parties.[3]

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[1] Order No. 07-015 is available here: https://apps.puc.state.or.us/orders/2007ords/07-015.pdf

[2] *See* Docket No. UE 198, Order No. 08-505, Appendix A, at 11, available at: https://apps.puc.state.or.us/orders/2008ords/08-505.pdf

[3] For example, PGE proposed a gas optimization method in Docket No. UE 377 pursuant to an agreement between parties in the 2020 AUT (Docket No. UE 359).

Q. What was the reasoning supporting this guideline?

A. The Commission adopted the guideline based on Commission Order No. 07-015, which provided that modeling enhancements should not be considered in AUT years. This decision was following PGE's recommendation at the time and primarily to address stakeholders' concerns that the AUT process does not allow for enough time to review the filings.[4]

Q. Why did PGE recommend in UE 180 to handle MONET modeling enhancements in GRC years instead of AUT?

A. We made the recommendation because at that time, in 2006, experience with the prior NVPC forecast process, the Resource Valuation Model (RVM), indicated that the range of logic, data, and other modeling changes that can occur was large and the effect of most such changes on the NVPC forecast was generally expected to be small. Therefore, we considered that there may be process efficiency gains by handling the modeling enhancements in GRC years instead of AUT years, and this would also provide parties sufficient time to evaluate these changes.[5]

Q. Do the arguments for not including modeling enhancements in AUT years still hold?

A. No. In the current energy market environment, there is an increased need for year-to-year NVPC forecast modeling flexibility to address new and rapidly evolving operational challenges and market changes impacting PGE's power operations that will likely require complex modeling changes with significant power cost impact. Some of the current operational challenges include:

- Changes to the regional energy market supply and demand fundamentals;
- Complexities and implications related to PGE's participation in the Western Resource Adequacy Program (WRAP);

[4] *See* Order No. 07-015 at 19, entered January 12, 2007.
[5] *See* Docket No. UE 180/PGE/400, Lesh-Niman at 19-20.

- The implementation of the regional EDAM; and
- New state decarbonization directives under House Bill (HB) 2021 and associated energy market and resource portfolio impacts.

Additionally, the regional market is experiencing transmission-related constraints which MONET is currently not set up to address. All these drivers require an adaptive approach to modeling NVPC to ensure a more accurate forecast as fundamentals change in both the marketplace and within PGE's portfolio between rate cases.

Q. Will stakeholders have sufficient time to thoroughly review the proposed modeling changes, given that the initial AUT filing date is on or before April 1?

A. Yes. Since the 2017 AUT (i.e., Docket No. UE 308), the procedural schedule for PGE's AUT filings has included five rounds of testimony, the same number as for GRCs, providing ample opportunity to review and raise issues regarding PGE's proposed modeling enhancements. Additionally, as provided in Table 1 below, the time between PGE's initial filing and stakeholders' opening testimony has been between 80 and 90 days in PGE's last five AUT filings, allowing for close to three months of initial discovery and review time.

Table 1

Docket No.	PGE's Initial Filing	Parties Opening Testimony	Days
UE 308 (2017 AUT)	1-Apr	20-Jun	80
UE 359 (2020 AUT)	1-Apr	25-Jun	85
UE 377 (2021 AUT)	1-Apr	26-Jun	86
UE 391 (2022 AUT)	1-Apr	30-Jun	90
UE 402 (2023 AUT)	1-Apr	23-Jun	83

Q. Did PGE propose MONET modeling changes within an AUT procedural schedule recently?

A. Yes. We proposed extensive modeling changes in our 2022 AUT, filed on April 1, 2021, in Docket No. UE 391. This was allowable as PGE submitted a 2022 GRC filing following the UE 391 initial filing, establishing 2022 as a GRC year.

Q. Did parties have sufficient time to review the modeling changes proposed by PGE in its 2022 AUT Docket No. UE 391?

A. Yes. The initial filing of UE 391 on April 1 included proposed modeling enhancements and was concluded prior to the end of the year, allowing for a January 1, 2022 price change. The procedural schedule allowed for five rounds of testimony and, in total, parties sent 189 data requests during the proceeding, to review the reasonableness of PGE's proposed enhancements and 2022 NVPC forecast.

Q. Did PGE provide an opportunity to parties to review proposed enhancements prior to the April 1 filing?

A. Yes. PGE held a workshop with parties on March 5, 2021, to discuss updates and enhancements to be included in the initial 2022 AUT filing. Similarly, as part of this proposal, PGE commits to holding a workshop with parties by March 15 of each AUT filing wherein PGE plans to propose modeling enhancements.

Q. Can other Oregon utilities include modeling enhancements in non-GRC years for power cost modeling?

A. Yes. PacifiCorp is allowed to include NVPC forecast modeling enhancements in their Transition Adjustment Mechanism (TAM) annual filings. PacifiCorp's TAM filings also provide for five rounds of testimony and parties have been able to fully litigate these proceedings without delay since the TAM was implemented in 2011.

Q. Is PacifiCorp's TAM materially different than PGE's AUT with respect to scope of proceeding and procedural schedule?

A. No. Both proceedings forecast NVPC for a future test year and both have initial filing dates in April provided there is no GRC filing earlier that year. Additionally, as with PacifiCorp's TAM, PGE uses the NVPC forecast from AUTs to establish direct access transition adjustments.

Q. Does PacifiCorp's typical TAM procedural schedule look materially different from PGE's AUT procedural schedule?

A. No. As shown in Table 2 below, the 2022 test year procedural schedules for the AUT and TAM filing are almost identical, clearly demonstrating that parties have the capability to review modeling enhancements within the procedural schedule of PGE's AUT.

Table 2
2022 AUT vs. 2022 TAM Procedural Schedules

Event	PGE's 2022 AUT (UE 391)	PacifiCorp's 2022 TAM (UE 390)
Company Filing	Thu 04-01-21	Thu 04-01-21
Workshop	Fri 05-28-21	Fri 05-14-21
Staff/Intervener Opening Testimony	Wed 06-30-21	Wed 06-09-21
Settlement Conference	Tue 07-13-21	Tue 06-22-21
Company Reply Testimony	Mon 07-26-21	Fri 07-09-21
Settlement Conference	Mon 08-02-21	Wed 07-14-21
Staff/Intervener Rebuttal Testimony	Mon 08-16-21	Fri 07-30-21
Company Surrebuttal Testimony	Mon 08-30-21	Fri 08-13-21
All Parties Cross-Examination Statements and Cross-Exam Exhibits	Wed 09-08-21	Fri 08-20-21
Hearing	Wed 09-15-21	Fri 08-27-21
Opening Briefs	Fri 09-24-21	Wed 09-15-21
Closing Briefs	Fri 10-08-21	Tue 10-05-21
Target Date for Commission Order	Tue 11-02-21	Mon 11-01-21

Q. Please summarize why PGE needs and should be allowed the flexibility to propose modeling enhancements in AUT dockets.

A. This flexibility is needed due to numerous factors that already impact power operations and will continue to do so. These factors include: 1) changes in resource mix and plant dispatch due to state legislature decarbonization directives; 2) expected transmission constraints due to having to wheel renewable generation from more diverse geographical locations; and 3) the implementation of regional capacity markets such as WRAP and EDAM. We discuss in more detail some of these factors in Section III.B and in PGE Exhibit 400. Furthermore, allowing PGE the ability to propose AUT modeling enhancements in AUT dockets would be consistent with PacifiCorp's allowed ability to include NVPC forecast modeling enhancements in their annual filings.

B. Capacity Planning

Q. Why do you discuss capacity planning in this testimony?

A. In the 2022 and 2023 AUTs (i.e., Docket Nos. UE 391 and UE 402) we provided details to describe how the energy resource capacity landscape has changed over the last two decades within the Western Electricity Coordinating Council (WECC), including the Northwest Power Pool (NWPP) footprint, and how these changes impact PGE's ability to meet customer peak loads. As these changes continue to impact the regional capacity landscape, similar to our 2022 and 2023 AUTs, capacity planning remains a key issue within PGE's actual operations and forecast NVPC. For the 2024 NVPC forecast, the circumstances and the market drivers remain similar to our discussion in the 2022 and 2023 AUTs.[6]

[6] *See* Docket No. UE 391, PGE Exhibit 100, Section III.A, available at: https://edocs.puc.state.or.us/efdocs/HAA/haa94954.pdf, and Docket No. UE 402, PGE Exhibit 100, Section III.A, available at: https://edocs.puc.state.or.us/efdocs/HAA/ue402haa94826.pdf .

Q. Do you provide a description of the factors driving regional capacity shortages and the associated impacts to PGE power operations in other exhibits to this rate case filing?

A. Yes. We provide a detailed description of the energy market drivers in PGE Exhibit 400. The dramatic and continued shift in regional energy resource capacity stack coupled with extreme weather events and load excursions and their impact on PGE's power operations and power costs warrant the adoption of an updated PCAM structure as well as MONET modeling changes to align the NVPC forecast with actual power operations. In this testimony, we describe the proposed MONET modeling changes and in Exhibit 400 we discuss the proposed changes to the PCAM structure.

Q. What are the most prominent impacts from the changing mix of energy resources in the WECC region?

A. First, region-wide shifts from firm and dispatchable resources to variable energy / non-dispatchable resources is causing a regional capacity shortage. This results in increased price volatility and an increased number of scarcity-price events during weather driven load excursions or other events that result in market tightness. These circumstances have resulted in a gap between how PGE dispatches its thermal plants in actual operations versus the economic dispatch in the MONET model. Specifically, MONET's deterministic economic logic dispatches PGE's marginal peaking resources, Beaver and Port Westward 2 (PW2), for energy at their maximum capacity for the majority of June through September and monetizes any generation length through wholesale market sales. This "length" assumes normal weather and average hydro and wind production with a market that is deep, liquid, and efficient. However, these conditions are not reflective of actual operations during summer months. Second, even during times of relatively normal load conditions, the regional shift from firm and dispatchable resources to variable energy resources (i.e., wind and solar resources) has resulted in increased price volatility as observed in the day-ahead energy market due to wind and solar generation uncertainty.

Q. Will PGE and its customers continue to be exposed to capacity shortage risks in 2024 and beyond?

A. Yes. As we further describe in PGE Exhibit 400, we expect the fundamental change in regional energy supply will continue to add significant complexity to the forecasting, planning, procurement, and dispatch decisions around PGE's capacity and energy needs. Consequently, PGE and its customers will continue to be exposed in 2024 and beyond to the risk of capacity shortages, extreme pricing volatility, and an increased number of scarcity pricing events during weather-driven load excursions or other market events. All these drivers will impact PGE's power operations and power costs incurred to meet customer loads reliably. We experienced these impacts in 2020, 2021, and continued to experience them in 2022.

Q. What evidence is there that energy markets are tighter and more volatile in recent years due to regional capacity shortages?

A. Evidence of the energy market tightness and volatility are: 1) the increased number of Energy Emergency Alert (EEA) events[7] declared by WECC reliability coordinators (RCs),[8] 2) the Mid-Columbia (Mid-C) day-ahead market price volatility and excursions seen in recent

[7] *See* NERC EOP-011-1, available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf Reliability Coordinator may declare whatever alert is necessary and need not proceed through the alerts sequentially. EEA 1 – All available generation resources in use. EEA 2 – Load Management procedures in effect. EEA 3 – Firm Load interruption is imminent or in progress.

[8] The WECC RCs are: Reliability Coordinator West (RC West), Southwest Power Pool (SPP), British Columbia Reliability Coordinator (BCRC), and Alberta Electric System Operator (AESO).

years,[9] and 3) the annual NERC Reliability Assessment report that projects "summer periods of energy shortfall risks in the next five years."[10]

Q. Did the number of WECC EEA events change in recent years?

A. Yes. WECC RCs declare an Energy Emergency Alert (EEA) when there is reliability risk due to a regional capacity shortage and market scarcity event often paired with runaway market price risk.[11] As clearly depicted in Figure 1,[12] the number and severity of EEAs declared by WECC RCs increased dramatically in recent years. With a West-wide transition to a greenhouse gas emission constrained economy, we expect PGE and our customers will continue to be exposed to significant market scarcity pricing risks and capacity shortages going forward in 2023, 2024, and beyond until the region reaches a new equilibrium. It is because of these risk factors during this time of rapid transition that PGE is one of the leading utilities advancing the WRAP to put standards for capacity planning as well as participating in the development of the EDAM that aims to access regional diversity of both demand and supply and build upon the existing intra-hour energy imbalance market (EIM) to which PGE is an active participant.

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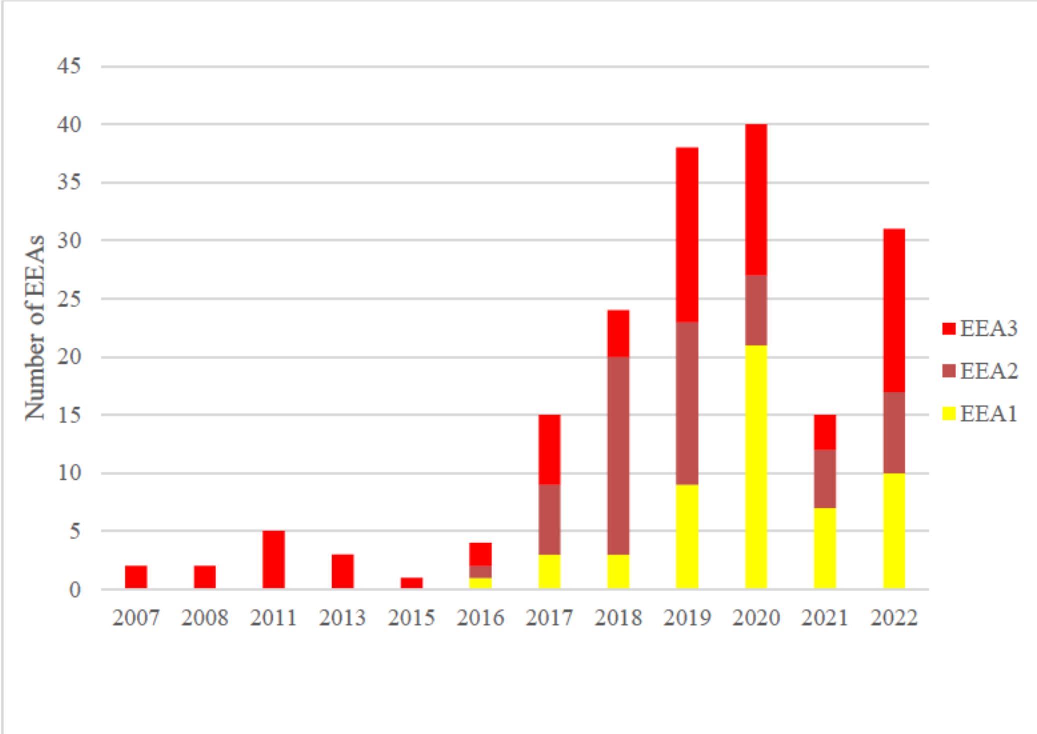
[9] Mid-C power prices settled at over $500/MWh in summer 2021 and over $1000/MWh in summer 2022 during weather events that caused load excursions and market tightness.

[10] *See* 2022 NERC Long Term Assessment Report at 11, available here: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf

[11] *See* NERC EOP-011-1 at: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf . Reliability Coordinator may declare whatever alert is necessary and need not proceed through the alerts sequentially. EEA 1 – All available generation resources in use. EEA 2 – Load Management procedures in effect. EEA 3 – Firm Load interruption is imminent or in progress.

[12] The data available does not include EEA1 and EEA2 events declared by WECC RCs prior to 2016.

Figure 1
WECC RCs EEA Events 2007-2022



Q. Does PGE anticipate capacity needs to increase?

A. Yes. We anticipate increased capacity needs associated with HB 2021 emission reduction requirements and increased power operations complexity related to the implementation of the WRAP.[13] Regarding the WRAP, while participation in the program will lead to increased power operations complexity, the associated costs are expected to be less than the cost to meet the challenge of reliably operating our system alone and without the benefit of broader resource diversification.

Q. How does HB 2021 impact PGE's capacity needs?

A. PGE anticipates that HB 2021 will likely increase the need for more flexible and dispatchable capacity. Variable energy resources (e.g., wind and solar) will increase the portfolio/regional

[13] Detailed information regarding the WRAP is provided on the program website: https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

need for flexible and dispatchable resources to both absorb the moment-to-moment variability and to generate electricity for a longer duration when variable resources are not generating.

Q. Does MONET's logic capture the risks associated with capacity shortages, extreme price volatility, and increased scarcity pricing events during load excursions or other market events?

A. No. As currently designed, MONET is a deterministic, energy-focused single stage model that is not set up to reflect the different planning windows (Term, Day-Ahead or Pre-schedule window, and Real-Time) within its forecasting logic and therefore, MONET is unable to address these risks. In fact, given the extremely high forward market heat rates, MONET's deterministic economic logic dispatches PGE's marginal peaking resources, Beaver and PW2, for energy at their maximum capacity for the majority of June through September and monetizes any generation length through wholesale market sales. As a result, in recent years, summer months are the lowest cost months in the MONET NVPC forecast. This result is in direct contradiction with recent actual operations where summer months have been the most expensive months of the year. Table 3 below provides the Q3 (i.e., July 1 through September 30) power cost variance between 2020 and 2022, when we have experienced more dramatic capacity shortages and associated extreme power cost.

Table 3
Q3 NVPC Variance

Year	Q3 NVPC Variance (millions)
2020	$14.2
2021	$67.8
2022[14]	$30.5

[14] The 2022 Power Cost Variance is still preliminary. Therefore, the Q3 NVPC Variance may by adjusted for the 2022 PCAM filing due July 1, 2023.

Q. Can or should PGE power operations follow the MONET dispatch logic during summer months?

A. No. PGE power operations should prioritize customer reliability ahead of portfolio optimization especially during peak months. PGE power operations would not be able to capture the full revenues associated with wholesale market sales that were modeled in the AUT during summer months, as described above. PGE power operations' primary responsibility is to optimize PGE's portfolio to reliably meet customer loads, while also complying with all applicable rules and regulations. In actual operations, if we were to sell that power forward, we would no longer have the cost-based dispatchable peaking resources available to meet load excursions, increasing exposure to run-away market prices, which, all else being equal, would cause system reliability risk and further increase actual NVPC. PGE power operations is generally only able to capture the economic margins on days with conditions that approximate the AUT forecast: i.e., normal temperature, hydro conditions, wind production, and perfect execution of hourly purchases and sales that equal the forward market prices at AUT. The timing and frequency of these normal weather days are not known or knowable at the time of the AUT or any time prior to the week or day-ahead planning. At the Day-Ahead planning window, variability of load, and wind and resource availability are better known, allowing power operations to commit to these forward market sales.

Q. What is the most significant risk for PGE, due to the gap between MONET modeling and actual power operations?

A. The most significant risk is that the AUT forecast materially underestimates the cost to serve customers during the summer months. Oftentimes, weather-driven scarcity pricing during summer months drives higher load than forecasted in the AUT and therefore PGE has to purchase additional power from the wholesale market at prices that exceed retail revenue rates to meet the incremental customer load, driving large power cost variances between the forecast and actuals, as exemplified in Table 3.

Q. What does PGE propose in its 2024 forecast to help mitigate the capacity shortage issue?

A. We propose to continue including a proxy Peak-for-Super Peak physical hedge contract effective during Q3 in the 2024 NVPC forecast. Additionally, we propose to model the annual cost associated with holding additional capacity reserves in the Day-Ahead planning window during "no touch" contingency events (Reliability Contingency Events or RCEs). Including these items in the 2024 forecast is consistent with PGE's operational strategy of executing structured transactions to help mitigate the exposure to weather-drive load excursions and holding additional capacity reserves in the Day-Ahead planning window[15] during RCEs, to ensure continued reliability.

Q. Please provide more detail regarding RCEs.

A. RCEs are declared by PGE when availability of our generating sites, as well as transmission and distribution equipment, is critical due to system conditions such as heavy loads, unexpected outages, or other constraints that reduce market liquidity. On these occasions, to minimize the potential of a power supply reduction or unplanned outage, a "no touch" period may be declared during which discretionary maintenance, operational changes, or testing on generating plants are postponed to maximize plant availability, reduce the risk of system outages, and limit or mitigate the threat posed to system reliability. RCE declarations are also intended to mitigate the risk of the RC-West[16] issuing an EEA for PGE's Balancing Area

[15] These operational capacity reserves are supplemental to WECC contingency reserves requirements.
[16] RC-West is the Reliability Coordinator (RC) of record for PGE's BAA and other 41 balancing authorities and transmission operators in the western United States and is operated by the CAISO.

Authority (BAA). In the last three years, RCEs have been declared most often due to load excursions and power supply and demand tightness during weather-related events (e.g., the 2021 and 2022 summer heat waves in the WECC and December 2022 below-normal temperatures and market tightness).

Q. Has PGE declared RCEs only during summer months in the last three years?

A. No. Although not as often as during summer months, PGE also declared RCEs in winter months: 1) in February 2021 due to temperature forecast below normal in the Portland Metro and regional area, driving up gas prices and 2) in December 2022 due to potential for a 1 in 10 peak load event and increasing energy market supply and demand tightness.

Q. How does PGE plan between the Day-Ahead and Real-Time operating windows when an RCE is declared?

A. During RCEs there is a high risk of deviation between the load forecasted in the Day-Ahead planning window and the actual (i.e., real-time) system load. Thus, to ensure reliable and least cost energy deliveries during RCEs, PGE power operations reserves a portion of PGE's capacity resources in the Day-Ahead operating window and assumes no wind generation will be available during either the real-time operating window super-peak hours (i.e., Hour Ending 17 – Hour Ending 22 in summer months) or the entire day. While this practice strengthens PGE's ability to reliably meet customer loads, it is contrary to MONET's single-stage economic dispatch logic. Including an assumption of RCEs into MONET will serve to more closely represent PGE's capacity planning process between the Day-Ahead and Real-time operating windows.

Q. Please explain how you propose to determine the forecast NVPC during RCEs.

A. We propose to model NVPC during RCEs using the following approach:

1. Set the number of days we expect to experience these types of events using a rolling three-year average of actual RCEs declared between July and September.
2. Determine the amount of capacity to be reserved based on load deviations between the Day-Ahead forecast load and actual system load during the last three years RCEs. For the 2024 NVPC forecast, this amounts to 146 MW to be reserved during the super peak period of the selected days.
3. To align with operational planning during RCEs, set the wind forecast to zero during the super peak hours of the selected days.
4. To reflect the lack of market liquidity, and the need for PGE to retain its resources during RCEs, set the market sales forecast in MONET during the selected days super peak hours to zero.
    a. Since this generation is assumed to be sunk to load instead of sold in the market, the NVPC impact of the no-touch event is reduced by this removed market quantity times the power costs in base retail rates and Schedule 125 prices. For the 2024 NVPC forecast we use the 2023 power costs in base retail rates and Schedule 125.
5. Use the Lydia[17] methodology to select the quartiles with a high load-net-wind (and thus high price) ranking to establish the days in the corresponding months that are most reflective of the conditions in which an RCE would occur.
6. Reserve (i.e., hold back) the capacity calculated in step 2 during super-peak hours in the

[17] Lydia is an hourly price shaping model, that is deterministic and mean-reverting, used to create hourly price distributions from forward (monthly) on- and off-peak prices to support the NVPC forecast in MONET. For more detail, *see* Docket No. UE 391, PGE Exhibit 100, Section III.B.

days established in step 5 by holding back Beaver 1-7. Beaver 1-7 is our marginal and least efficient dispatchable resource, and it is the most cost-effective option for estimating power costs during RCE.

Q. How many RCEs have you experienced in the last three years in the months of July through September?

A. In the summers of 2020-2022, there have been on average 7.85 days in which an RCE was declared, or an average of 2.62 days per month in Q3. Table 4 below shows the number of days in each summer month for the past three years that an RCE was declared:

Table 4
Actual RCEs

Month	2020	2021	2022	3yr Avg
July	2.5	1.7	4.7	2.96
August	3.7	2.1	0	1.93
September	7.0	0	3	2.96

An average of 2.62 days per month in Q3 is used instead of the individual monthly averages, since there is no statistically significant pattern concerning the distribution of events between the three months in summer. As shown in Table 4 above, in 2020 September had the most event days, in 2021 August has the most event days, and in 2022 it was July.

Q. What is the power cost impact associated with the RCE power cost recovery?

A. The power cost impact is a $3.9 million increase to the 2024 NVPC forecast.

Q. PGE's proposed PCAM reform discussed in PGE Exhibit 400 includes a feature that allows for full recovery/refund of costs/benefits incurred during RCEs, subject to certain criteria. Why is it appropriate to also model the forecast cost for meeting customer needs during RCEs in the NVPC forecast?

A. The purpose of the MONET modeling is to forecast annual NVPC as accurately as possible. Because we expect increased numbers of RCEs due to climate change driven weather events and increasing energy market supply and demand tightness due to the regional shift to intermittent, non-dispatchable resources, it is appropriate to forecast the associated cost impact. Additionally, as described previously in this section, PGE's power operations' primary function is to deliver reliable energy to customers. During RCEs, PGE is unable to dispatch our resources in the most economic manner, consistent with the MONET economic based dispatch. Therefore, any power cost risk should be equally shared between PGE and customers. The RCE power cost modeling and the RCE feature of the proposed PCAM will function as a balancing account and ensure that neither customers nor PGE are overcharged during these events.

Q. As mentioned above, you continue to include a proxy Peak-for-Super Peak contract in the 2024 NVPC forecast. Is the Peak-for-Super Peak a complement to or replacement of the RCE capacity planning estimated costs?

A. The Peak-for-Super Peak is a complement to the RCE capacity planning modeling. PGE power operations needs both items to address the reliability risks during summer months. The Peak-for-Super Peak is a physical hedge contract that ensures better shaping of PGE generation to match customer load during super peak hours. However, for annual capacity contingency planning, this contract is already accounted for in the resource stack needed to meet the Day-Ahead load forecast. Therefore, the deviation between the load forecasted in the Day-Ahead and actual system load during RCEs is above and beyond what is accounted for with the Peak-for-Super Peak contract.

Q. What are the terms of the Peak-for-Super Peak proxy contract?

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

[redacted]

[END CONFIDENTIAL]

Q. Will PGE seek to execute other capacity contracts for Q3 months?

A. Possibly. We will continue to evaluate PGE's capacity needs and make procurement decisions according to those needs in the least cost least risk manner. Should we seek additional capacity through structured contracts we will notify parties and provide the agreements in MONET updates.

C. Washington State Cap-and-Invest Program

Q. Please provide detail regarding the status of Washington's Cap-and-Invest program.

A. In 2021, the state of Washington passed the Climate Commitment Act,[18] which established a comprehensive, market-based cap-and-invest program[19] aimed at reducing pollution and achieving the greenhouse gas (GHG) limits set in the state law.[20] The Washington Department of Ecology finalized the cap-and-invest program regulations in October 2022 and the program was launched on January 1, 2023. Thus, entities that are covered under the program started incurring emission compliance obligations January 1, 2023.

Q. Do you anticipate that PGE will be a covered entity under the program?

A. Yes. Generally, businesses are a covered entity under the program if they generate emissions that exceed 25,000 metric tons of CO2 equivalent per year (MTCO2e). We expect that PGE

[18] Available at: https://ecology.wa.gov/Air-Climate/Climate-Commitment-Act
[19] Available at: https://ecology.wa.gov/Air-Climate/Climate-Commitment-Act/Cap-and-invest
[20] Together with existing policies advancing clean energy and zero-emission vehicles, these new laws put Washington on a path toward achieving the greenhouse gas limits set in state law: 45% below 1990 levels by 2030, 70% below 1990 levels by 2040, and 95% below 1990 levels and net-zero carbon emissions by 2050.

will be an importer of energy in the state of Washington at levels that are likely higher than the emissions threshold of 25,000 MTCO2e and therefore, we anticipate being a covered entity[21] subject to the program requirements. Other covered entities include fuel suppliers, natural gas and electric utilities, waste-to-energy facilities (starting in 2027), and railroads (starting in 2031).

Q. What does it mean that PGE is a covered entity?

A. This means that PGE needs to comply with the Washington Cap-and-Invest program requirements when importing power into the state of Washington.

Q. Under the Washington Cap-and-Invest rules, what is the definition of imported electricity?

A. Imported electricity is defined as electricity generated outside of Washington state with a final point of delivery within the state.

Q. Under the Washington Cap-and-Invest rules, when do you anticipate PGE will be identified as the responsible importer?

A. In general, we anticipate that PGE will be the responsible importer when PGE is listed on the electronic tag (i.e., e-tag) as the purchasing selling entity (PSE) on the row (i.e., leg) of the physical path that crosses the state border.

Q. Do the Washington Cap-and-Invest rules impact PGE's trading at the Mid-C trading hub?

A. Yes. A primary market for PGE's power trading activity is the Mid-C trading hub. Therefore, beginning January 1st, PGE must anticipate incurring a carbon obligation for many of the trades that PGE transacts under the standard Mid-C trading product, because the energy supply

[21] As defined in the Revised Code of Washington State 70A.65.010(23), available here: https://app.leg.wa.gov/RCW/default.aspx?cite=70A.65.010&pdf=true

supporting PGE's trading activity is often the economic dispatch of PGE's thermal resources that are not located in the state of Washington (i.e., PGE would anticipate being the responsible importer). The Washington Cap-and-Invest rules also impact bilateral trading in either term or real-time markets. That is, when PGE trades bilaterally, PGE must understand whether the power will ultimately sink in Washington to appropriately price offers shared during trade negotiations.

Q. When is the cost impact most prominent?

A. The cost impact is most prominent during summer months which coincides with an observation we shared in an earlier section of our testimony: MONET's deterministic economic logic dispatches PGE's marginal peaking resources, Beaver and PW2, for energy at their maximum capacity for the majority of June through September and monetizes any generation length through wholesale market sales. These wholesale market sales decrease customer cost. For 2024, wholesale sales will reduce $143.3 million of customer costs. With the Washington Cap-and-invest program, these sales come with additional costs.

Q. How will PGE's power costs be impacted by the Washington Cap-and-Invest program?

A. With the anticipation that PGE will be a covered entity, every energy unit sale that PGE sources from production outside of Washington state and has a final point of delivery in Washington state will carry an associated carbon emission rate that needs to be covered under the program through carbon allowances or carbon offset credits[22] (i.e., compliance instruments). The carbon emission rate will therefore carry an associated cost that needs to be accounted for in the NVPC forecast.

[22] Offset credits come from investing in projects that help reduce carbon that provide a direct environmental benefit to the state of Washington. Washington allows offset credits for up to 8% of covered emissions for the first compliance period. PGE does not have such offsets at this time.

Q. How does the Washington Cap-and-Invest program work?

A. The Washington Cap-and-Invest program sets a limit, or cap, on overall carbon emissions in the state of Washington and requires covered entities to obtain compliance instruments equal to their covered GHG emissions during a compliance period. These allowances can be obtained through quarterly auctions or bought and sold on a secondary market. The GHG cap will be reduced over time to ensure that the state of Washington achieves its decarbonization goals.

Q. What is the Washington Cap-and-Invest program compliance period and requirement?

A. The length of a compliance period under the cap-and-invest program is four years. At the end of each compliance period, participating entities must submit compliance instruments equal to their covered GHG emissions for all four years. In addition, by November 1 of each year, participants must submit compliance instruments equal to 30% of prior year emissions. That means that if an entity only submits the required 30% annually, at the end of the four-year compliance period, it would need to submit the remaining 70% of its total emissions.

Q. When will the first auction occur?

A. The first auction for allowances will take place in February 2023. Consequently, we currently do not have clear information regarding the cost of compliance with the Washington Cap-and-Invest program requirements. The only information regarding the carbon allowance cost is currently the auction floor and ceiling prices established under the Washington Cap-and-Invest program.

Q. What are the carbon allowances auction floor and ceiling prices?

A. For 2023, the carbon allowance floor price is $22.20/MTCO2[23] and the ceiling price $81.50/MTCO2.[24] It is expected that the final auction price will settle in between these limits and, for forecast purposes in the initial 2024 NVPC forecast filing, we propose using a conservative price of $22/MTCO2 for carbon allowances.

Q. Will you update the carbon allowance price with the actual February 2023 auction price?

A. Yes, we will update this price in subsequent MONET updates to reflect the actual carbon allowance price established through the February 2023 auction.

Q. You mention above that the Washington Cap-and-Invest program started on January 1, 2023. Did you include any estimated power cost impact in the 2023 NVPC forecast in UE 402?

A. No. As previously described, the Washington Cap-and-Invest program regulations were finalized and adopted in October 2022. Given the UE 402 procedural schedule and the fact that there was not sufficient information to accurately forecast the cost of compliance within the Washington Cap-and-Invest program at the time when the 2023 NVPC forecast was processed, we did not include any associated costs. However, now that the regulations are finalized, it is appropriate to include the expected impacts in the 2024 NVPC forecast.

Q. How do you reflect the impact of the Washington Cap-and-Invest program in the 2024 NVPC forecast?

A. To reflect an initial estimate of the power cost impact associated with the adoption of the Washington Cap-and-Invest program, we apply the $22/MTCO2 assumed cost of carbon

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[23] *See* https://apps.ecology.wa.gov/publications/documents/2202060.pdf
[24] *See* https://apps.ecology.wa.gov/publications/documents/2202059.pdf

compliance and a blended portfolio emission rate of 0.437 MTCO2e/MWh[25] to all market sales forecast in MONET, net of sales volumes estimated outboard for COB transactions. Details regarding the methodology are provided in MFRs.

Q. What is the market sales volume resulting from the MONET model economic dispatch and then reduced by the estimated COB transactions?

A. Table 5 lists the monthly market sales volumes resulting from the MONET model and the market sales volumes estimated outboard of the MONET model for COB transactions. After adjusting for COB transaction, the forecast 2024 Mid-C volumes eligible for carbon obligation under the Washington Cap-and-Invest Program are provided in the third row.

Table 5
MONET Market Sales Volumes

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MONET Market Sales MWh)	25,240	122,918	93,163	228,252	124,000	247,654	363,584	279,094	200,099	110,131	16,193	5,607
COB Transactions (MWh)	87,439	30,795	90,009	64,300	85,831	102,272	99,941	96,925	84,569	83,688	109,274	84,517
Mid-C MWh Eligible for Carbon Obligation	-	92,122	3,154	163,952	38,168	145,383	263,643	182,169	115,530	26,443	-	-

Q. Why does PGE reduce the MONET sales volume by the estimated outboard COB transactions?

A. In practice, PGE recognizes that not all sales resulting from the MONET model dispatch will ultimately sink in Washington and create a carbon obligation for PGE. Therefore, we used our estimate of COB transactions as a basis for reducing the sales volume eligible for incurring a compliance obligation cost from the Washington Cap-and-Invest program.

[25] Washington State greenhouse gas emission content in electricity for unspecified electricity is provided in WAC 173-444-040(4) – Unspecified Electricity, Equation 4, available at: https://apps.leg.wa.gov/wac/default.aspx?cite=173-444-040

Q. What is the NVPC impact associated with the Washington Cap-and-Invest program?

A. The Washington Cap-and-Invest program cost reduces the MONET market sales benefit in the initial 2024 NVPC forecast by approximately $9.9 million, from $143.3 million to $133.4 million. By month, the forecast MWh volume and carbon obligation cost under the Washington Cap-and-Invest is listed in Table 6, below.

Table 6
Washington Cap-and-Invest NVPC Impact

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mid-C MWh Eligible for Carbon Obligation	-	92,122	3,154	163,952	38,168	145,383	263,643	182,169	115,530	26,443	-	-
Carbon Obligation Cost	$ -	$ 885,664	$ 30,321	$1,576,235	$366,951	$1,397,709	$2,534,667	$1,751,375	$1,110,709	$254,220	$ -	$ -

D. Gas Storage and Gas Resale Optimization Enhancements

Q. Does PGE propose enhancements to both the gas storage and the gas resale optimization methods for the 2024 NVPC forecast?

A. Yes. As we continue to gain experience operating the North Mist facility, we propose updates to address operational complexities involving certain items that impact fueling priority and the availability of non-firm delivered gas, and also to ensure more cost-effective dispatch of the Port Westward (PW)/Beaver complex.[26] The proposed updates will better align the forecast benefits associated with gas operations optimization to actual operational constraints and realities. Additionally, we propose an update to the gas resale method to more accurately represent actual Gas Transmission Northwest (GTN) gas pipeline availability experienced in recent years.

[26] The PW/Beaver complex includes PGE's gas thermal plants PW1, PW2, Beaver Units 1-7, and Beaver Unit 8.

1. Gas Storage Optimization Method Updates

Q. Please summarize PGE's gas storage optimization method.

A. In the 2021 AUT, PGE proposed a method to capture potential natural gas storage optimization benefits that could be realized based on North Mist storage injection and withdrawal cycles relative to forward gas prices at the Sumas and Rockies markets and the economic dispatch of the PW/Beaver complex. More specifically, in order to determine a potential gas storage optimization monetary benefit, PGE evaluates a weighted average cost of gas (WACOG) in storage based on inventory levels and market prices, and planned gas storage injections during months of lower forecasted natural gas market prices. PGE added further refinements and enhancements to the forecasted dispatch costs for the PW/Beaver complex based on an economic optimization of the available fuel supply at the complex to meet expected fuel demand and prioritize plant heat rate efficiency.[27] Additionally, the gas modeling informs run hour constraints for Beaver's dispatch based on the fuel availability at the PW/Beaver Complex.

Q. What updates are you proposing for the gas storage optimization method?

A. We propose the following updates:

1. Adjust the North Mist gas supply at the PW/Beaver complex to prioritize PW2 and Beaver dispatch during high load hours (HLH) over low load hours (LLH),
2. Update delivered gas availability for March and November consistent with PGE actual operational constraints and recent years actual fuel supply,
3. Adjust the PW2 renewable integration fuel hold, and
4. Update modeling for Beaver Unit 8 to reflect fueling availability.

[27] *See* more details in Docket No. UE 391, PGE Exhibit 100 at Section III.D, available at: https://edocs.puc.state.or.us/efdocs/HAA/haa94954.pdf

<u>*North Mist Gas Supply Update*</u>

Q. Why do you propose updating the North Mist gas supply to the PW/Beaver complex?

A. Currently, the MONET model dispatches PW2 and Beaver plants based on economics during HLH and LLH, irrespective that fueling requirements for both plants are provided by the same North Mist gas supply. Although the gas optimization modeling does inform run hour constraints for Beaver to prevent plant dispatch from exceeding the fuel supply, no fueling constraints are applied to any other plants. The result is that MONET considers PW2 dispatch during LLH and HLH before adjusting fuel availability to dispatch Beaver, and may use most if not all the fuel supply. In consequence, the gas optimization model essentially runs out of gas supply needed to fuel Beaver during expensive HLH, increasing the power cost forecast. PW1 is not considered in this proposal as it is prioritized before PW2 and Beaver in the gas optimization method based on heat rate efficiency, and dispatches as baseload during both LLH and HLH.

Q. How do you implement this update in the NVPC forecast?

A. The MONET model currently dispatches the gas plants using a single fuel price for both on-peak (i.e., HLH) and off-peak (i.e., LLH). To improve the gas optimization method, we propose modeling separate fuel prices for HLH and LLH for both PW2 and Beaver. This separation will enable the gas optimization method to consider the dispatch of PW2 and Beaver with prioritization for fuel first during HLH and then second during LLH, resulting in improved dispatch economics. Applying separate fuel prices for PW2 HLH/LLH and Beaver HLH/LLH, MONET will economically optimize the plant dispatch and ensure the plants run more during HLH, ensuring improved plant dispatch economics.

Q. What is the power cost impact related to this update?

A. Implementing this update reduces the 2024 NVPC forecast by approximately $4.3 million.

Delivered Gas Update

Q. Please discuss the gas supply at the PW/Beaver complex.

A. PGE holds a total of 111,805 dth/day[28] of firm transportation rights on the Northwest Pipeline for firm delivery at the Kelso-Beaver (KB) pipeline to fuel the North Mist gas storage and the PW/Beaver complex. The daily withdrawal rate from the North Mist gas storage is between 64,800 and 120,000 dth/day, depending on the storage inventory level. Additionally, PGE relies on 47,921 dth/day of non-firm delivered gas to meet the PW/Beaver fuel demand throughout the year, except for winter months.

Q. Does the current gas storage optimization modeling fully account for the limited availability of firm delivered gas during the winter months?

A. No. The current gas storage optimization method includes Beaver plant parameter constraints that limit the plant's dispatch to reflect the natural gas transportation and storage capabilities, so the MONET model does not assume any delivered gas availability between December and February. However, contrary to actual PGE power operations experience with gas availability, the model assumes full availability for the months of March and November.

Q. Why is there limited availability of firm delivered gas during colder months?

A. During colder months, PGE's access to firm delivered gas is limited because of competing local natural gas distribution companies (LDC) that need to meet their heating loads. Consequently, there is little to no firm delivered gas supply available for fueling power plants.

[28] Dekatherm (Dth) is a unit of energy used to measure natural gas and is equal to one million British thermal units.

Q. For planning purposes in the operational year, does PGE rely on delivered gas between November and March?

A. No. Because LDCs and other firm transport holders utilize more of their transport to meet heating loads, we assume zero availability during the period between November and March for planning purposes to ensure we meet our load serving obligation with reliable energy deliveries.

Q. How do you implement the update to delivered gas availability during November through March in the MONET model?

A. Consistent with our operational planning, we remove the delivered gas supply availability during the months of November through March from the gas storage optimization workbook and then adjust the PW2 and Beaver plant output to meet fuel constraints.

Q. If delivered gas is available during November through March, will the MONET model be adjusted?

A. Yes. PGE evaluates market opportunities to transact for delivered gas throughout the year. In the event that delivered gas becomes available for the 2024 test year, the MONET model will be adjusted to reflect the physical volume of delivered gas transacted for the months (November through March) that are currently set to zero.

Q. What is the impact to the 2024 NVPC forecast associated with the delivered gas update?

A. The delivered gas update results in a $11.7 million increase to the 2024 NVPC forecast.

PW2 Renewable Integration Fuel Hold

Q. What is the PW2 renewable integration hold?

A. The current gas storage optimization method derates the North Mist injections and withdrawal rates by 5,000 dth/day to support PW2 additional fuel needed during the ancillary services dispatch in MONET. However, after evaluating the model's current ancillary services dispatch and additional fuel need for PW2, the results indicate it is no longer necessary to hold the 5,000 dth/day.

Q. What is your proposal regarding the PW2 renewable integration fuel hold?

A. We propose to remove the fuel hold from the gas storage optimization method. This update reduces the 2024 NVPC forecast by approximately $1.9 million.

Beaver Unit 8 Fueling Availability

Q. Please describe the Beaver Unit 8 modeling.

A. Beaver Unit 8 is modeled as a separate plant within MONET and is not included in the gas optimization modeling. It is modeled with a single annual capacity rating and dispatched in the NVPC forecast consistent with the dispatch logic applied to the other natural gas thermal plants. It is primarily dispatched against the forward market prices, with derations applied for planned maintenance and forced outages. Its dispatch does not currently consider the fueling requirements at the PW/Beaver Complex.

Q. Why was Beaver Unit 8 not included in the gas optimization modeling prior to the 2024 NVPC forecast?

A. The gas optimization modeling was initially designed in the 2021 AUT to capture potential benefits of stored gas based on North Mist gas storage operations. Beaver Unit 8, although also located at the PW/Beaver complex, is not interconnected to receive fuel from the North Mist storage facility, and thus was not considered in the gas storage optimization. Additionally, at the time of implementing gas optimization modeling, Beaver Unit 8 had historically been forecast in MONET with limited dispatch due to its high heat rate generally economically displacing it relative to the forward market prices. However, market conditions have continued to shift since then and Beaver Unit 8 dispatch has gradually increased in the NVPC forecasts, with its output not reflective of fueling availability.

Q. What is your proposal for Beaver Unit 8?

A. We propose to modify the modeling for Beaver Unit 8, such that its dispatch capability will reflect fueling availability at the PW/Beaver complex. Consistent with the fueling priority logic built into the gas optimization model, Beaver Unit 8 will consider the remaining fuel available after meeting fueling requirements for PW1, PW2, and Beaver Units 1-7. When remaining fuel is limited, Beaver Unit 8 will include a deration factor to limit the dispatch in order to prevent exceedance of the total fuel supply.

Q. How do the fueling availability and plant dispatch assumptions for the gas optimization modeling of the PW/Beaver complex in the 2024 NVPC forecast compare with the NVPC forecast in prior years?

A. Please see Table 7 below, comparing the remaining fuel availability and plant economic dispatch assumptions used in the gas optimization modeling. The fuel availability is based on remaining fuel supply relative to total fuel supply after allocating fuel to the plants included in the gas optimization modeling. The economic dispatch is based on the expected plant run hours prior to the model adjusting for plant outages and fuel constraints. We conclude that over time, the fuel remaining at the PW/Beaver complex following estimated fuel burn for PW1, PW2, and Beaver 1-7 has gradually reduced due to increased plant dispatch based on economic factors[29] in the MONET model. Because Beaver Unit 8 is dispatched in the model without consideration for remaining fuel, it could result in exceedance of the total fuel supply.

[29] Economic dispatch based on expected run hours comparing plant dispatch costs relative to forward market prices.

Table 7
Percentage of Fuel Availability and Economic Dispatch Assumptions 2021-2024[30]

	2021 AUT	2022 AUT	2023 AUT	2024 Forecast
Remaining Fuel Availability	38%	20%	6%	4%
PW1 - Economic Run Hr	73%	83%	94%	96%
PW2 - Economic Run Hr	31%	64%	83%	87%
Beaver 1-7 - Economic Run Hr	23%	56%	76%	82%
Beaver 8 - Economic Run Hr	14%	42%	66%	72%

Q. What is the impact to the 2024 NVPC forecast?

A. The Beaver Unit 8 fueling availability constraint results in an increase of approximately $6.3 million to the 2024 NVPC forecast.

2. Gas Resale Optimization Update

Q. Please summarize PGE's gas resale optimization method.

A. PGE's gas resale method estimates the potential net power cost benefit that could be realized from gas sales and purchases on the GTN pipeline that fuels the Carty and Coyote plants. To determine the gas resale optimization margins[31] PGE first evaluates if there is a modeled gas surplus. If there is a gas surplus in any given day, MONET will seek to attain a modeled power cost benefit and sell the gas surplus at a price approximating daily physical gas traded at the Stanfield trading hub. Alternatively, if market heat rates are causing MONET to dispatch Carty and Coyote in excess of PGE's gas supply (i.e., creating a gas deficit), MONET will fill the gas deficit with delivered gas purchased at a premium, thereby reducing the total power cost benefit from gas resale opportunities.

[30] Remaining fuel availability and economic run hour percentages are based on the assumptions used in gas optimization modeling for PW1, PW2, and Beaver 1-7. Similar modeling logic was applied to Beaver 8 to compare each of the forecast years.
[31] *See* detailed description of the method and constraints in Docket No. UE 377, PGE Exhibit 100, at Section III.B.

Q. What update do you propose to the gas resale optimization modeling?

A. We propose to replace the current method for reducing GTN pipeline availability (i.e., a reduction based only on an estimate of planned pipeline maintenance) with a historical year of actual flow volumes that more fully captures variables that impact pipeline availability.

Q. What data did PGE use to determine the GTN pipeline availability?

A. PGE used historical scheduled quantity data that can be accessed from the TC Energy website[32] for GTN to determine total gas flows by PGE through the Kingsgate Receipt. PGE calculated the transport utilization by comparing the historical actuals with the maximum GTN capacity (119,500 dth/day). The transport utilization is then input into the MONET gas resale model to estimate the GTN pipeline availability for the test year.

Q. What is included in the transport utilization data?

A. The historical data contains all mainline gas transport flows, including gas to fuel the Carty and Coyote Springs gas plants, and gas resales at Stanfield. Additionally, the data captures constraints which may affect transport utilization, including:

- planned maintenance (and deviations from the planned maintenance schedules);
- unplanned outage events;
- schedule reductions on gas resales to third-parties; and
- inability to execute gas transactions due to lack of market depth preventing optimization of available gas transport.

[32] The GTN availability data can be accessed with a TC Plus account: http://tcplus.com/GTN

Q. Does the gas resale optimization consider the above factors for the GTN pipeline availability?

A. No. The gas resale optimization assumes the same GTN pipeline planned maintenance schedule as was used in the year prior to the test year. Specifically, it uses the GTN's 2023 planned maintenance schedule and applies that to the 2024 test year.

Q. Why does PGE seek to include the additional constraints?

A. The additional constraints, specifically unplanned and schedule reductions are constraints that reduce transport utilization, and therefore, are reasonable adjustments to the pipeline availability used in the existing method.

Q. How do you model this update in the 2024 NVPC forecast and how do you limit the update to non-economic drivers?

A. We use 2022 historical data for transport utilization to derive the GTN pipeline availability to be used in MONET modeling.

Q. Why do you use only 2022?

A. We use only 2022 as a reference year because 2022 best represents transport utilization primarily impacted by non-economic conditions. That is, throughout 2022, PGE was often able to execute gas transactions that captured locational price spreads when it was economically justified. Therefore, the level of transport utilization remains high across all months in the year. A review of the 2020-2021 data will show months in which GTN transport utilization is significantly lower relative to 2022. While a detailed accounting of each gas schedule is not practical, the differences in transport utilization are likely due to fewer economic opportunities for gas trading activity focused on attaining power cost benefits from locational spreads.

Q. How does the proposed GTN pipeline utilization data compare to what was used as an assumption in the 2021, 2022, and 2023 NVPC forecasts?

A. Our proposed methodology results in 93.72% GTN pipeline availability in 2024. See Table 8 below comparing actual GTN pipeline transport utilization and forecast pipeline availability in the AUT forecasts.

[BEGIN CONFIDENTIAL]

Table 8
GTN Pipeline Availability 2020-2022

[redacted]

[END CONFIDENTIAL]

Q. What is the impact to the 2024 NVPC forecast?

A. The GTN pipeline availability update results in an increase of approximately $2.4 million to the 2024 NVPC forecast.

F. Other Items

1. <u>2024 Physical Gas Call Option Contract</u>

Q. Please describe the gas call option contract you include in the 2024 NVPC forecast.

A. We include a proxy contract for a physical gas call option that will protect PGE and customers from gas price excursions risks during 2024 winter months.

Q. Why is it important that PGE execute this type of contract?

A. Natural gas prices in Western US markets have soared in Q4 of 2022 and continue to stay elevated into Q1 of 2023. As described by the EIA, the spike in natural gas prices was due to “widespread, below-normal temperatures, high natural gas consumption, reduced natural gas flows, pipeline constraints, including maintenance in West Texas, and low natural gas storage levels in the Pacific region."[33] From the end of November through mid-December below-normal temperatures in the Pacific Northwest and California led to increased demand for natural gas for heating. The natural gas supply did not keep pace with the increased demand because there was reduced pipeline capacity due to maintenance in the West Texas and low natural gas inventories in the Pacific region. The low inventories in the West are primarily due to inventories being used for energy generation to meet peak loads during the Q3 2022 heat waves as well as lower hydro generation in October and November of 2022 due to dryer than normal conditions. Operational experience from the last two years (i.e., 2021, 2022) indicates that the high natural gas market price and volatility will continue in future winter months and could result in significant power cost impacts. Therefore, to address the natural gas market price risk, we are planning to execute a physical natural gas call option to be effective in the months of January, February, and December 2024.

Q. What contract terms are you modeling in the initial 2024 NVPC forecast

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

Q. Will you update the terms of the contract?

A. Yes. Once the actual transaction is executed for 2024, we will remove the proxy contract and include the actual physical gas call option contract in the 2024 NVPC forecast. Also, upon execution, we will provide the contract to parties and include it in the immediately following MONET filing.

[33]U.S. Energy Information Administration - EIA - Independent Statistics and Analysis: https://www.eia.gov/todayinenergy/detail.php?id=55279

Q. What is the net power cost impact associated with the 2024 physical gas call option contract?

A. The net power cost impact is a $2.2 million increase to the initial 2024 NVPC forecast. However, as mentioned above, we will update the impact after we execute the actual 2024 physical gas call option contract.

2. <u>California-Oregon Border (COB) Trading Margin:</u>

Q. What is the COB trading margin?

A. PGE's current method uses actual hourly data for trading activities and market forward curves to produce a granular forecast result that is consistent with PGE's historical ability to use its firm transmission access to sell or purchase power at the COB market and realize NVPC benefits from the price spread between the Mid-C and the COB markets.

Q. Does the current model account for COB transactions executed in advance of the test year?

A. No. The model does not and cannot account for transactions executed in advance of the test year. Specifically, if PGE were to have the opportunity to execute a deal before final MONET update for the test year to lock in certain benefits from transacting at COB, that transaction would be included in the test year forecast within the contract and curves updates. As the COB trading margin model is not sufficiently dynamic to ensure those transactions are also accounted for in the model, the above deal would be additive to the forecasted trading margin benefit, potentially resulting in both a double counting of benefits, and unrealistic transaction volumes at COB, in excess of our transmission rights.

Q. How do you propose to adjust the model to allow for such transactions to be accounted for?

A. We propose adjusting the COB trading margin benefit calculated outboard of MONET to remove any benefit associated with COB transactions executed in advance of the final MONET contracts update. The benefit associated with these transactions will be reflected in PGE's contracts and curves update; thus, customers will receive the full amount for COB trading margin forecast.

Q. Did you execute any 2024 COB transactions at the time of this filing?

A. No. If we execute any 2024 COB transactions before the final MONET update in this case, we will provide the details to parties through the periodic MONET updates.

Q. Does this update have any impact on the 2024 NVPC forecast?

A. No, there is no cost impact.

3. Extended Day-Ahead Market (EDAM):

Q. Why do you discuss EDAM?

A. We provide detail on the EDAM in compliance with the terms of the UE 402 Stipulation adopted through Commission Order No. 22-427. Parties to UE 402 agreed that PGE will hold a workshop on the EDAM and will also provide testimony in the 2024 AUT including detail regarding:

1. Resource Sufficiency Evaluation, Greenhouse Gas accounting and costs, and Transmission impacts; and
2. Potential costs and benefits from participation in the EDAM, based on the information that is most recent at the time of the 2024 AUT filing.

Q. Has PGE held the EDAM workshop?

A. Not yet. PGE will hold the EDAM workshop concurrently with the Quarterly Power Supply Update scheduled for February 22, 2023.

Q. What is the EDAM?

A. After numerous workshops and collaboration with stakeholders and market participants, CAISO published its final proposal for an EDAM on December 7, 2022. As described in the final proposal:

> [T]he proposed EDAM is a voluntary day-ahead electricity market [that is expected] to more efficiently and effectively integrate renewable resources and address significant operational challenges presented by rapidly changing resource mix, emerging technologies, and the impacts of climate change. EDAM builds upon the ability of the Western EIM to increase regional coordination, support state policy goals, and meet demand cost-effectively.[34]

The EDAM is expected to go live in 2024.

Q. Has PGE made a decision regarding participation in the EDAM?

A. Not yet. PGE will continue to monitor the development of the EDAM and will make a decision regarding participating when there are more details regarding the operational impacts.

Q. Please provide detail regarding the EDAM resource sufficiency evaluation (EDAM RSE).

A. See extensive discussion on the EDAM RSE in the CAISO EDAM Final Proposal, Section II.B.2, starting at page 59. As provided in the EDAM final proposal, the EDAM RSE is intended to ensure that each EDAM entity can meet its BAA obligations (forecasted demand, uncertainty, ancillary service requirements) prior to engaging in transfers with other participating BAAs through the day-ahead market. The EDAM RSE tests whether each

[34] CAISO EDAM Final Proposal at page 1, available at: http://www.caiso.com/InitiativeDocuments/FinalProposal-ExtendedDay-AheadMarket.pdf

participating BAA has sufficient capacity and flexibility ahead of participating in the day -ahead market at 10:00 a.m. and imposes consequences for a BAA that fails the evaluation. Passing the EDAM RSE ensures that all resulting EDAM transfers allow a participating BAA to access more economic energy than it would have without access to the EDAM.

Q. What are the EDAM RSE requirements?

A. The EDAM RSE will test an EDAM entity's ability to meet its BAA requirements, including demand and ancillary service obligations, in each of the 24 hours of the day-ahead market run, as well as the flexibility to ramp between the requirements in each hour. The following summarizes the elements of the EDAM RSE:

1. Forecasted Demand: each BAA needs to demonstrate its ability to meet its forecast demand prior to participating in the EDAM.
2. Imbalance Reserves: The proposal is that each EDAM BAA possess sufficient supply and flexibility necessary to meet its imbalance reserve obligation.
3. Flexibility Requirement: EDAM BAAs will have to meet forecasted ramping requirements across the 24-hour period which is an integral component of being resource sufficient.
4. Ancillary Services Requirement: Each EDAM BAA will define its ancillary service requirements consistent with its reliability requirements.
5. Reliability Capacity Bidding: The proposal is that all entities participating in EDAM that submit a day-ahead energy bid into the Integrated Forward Market (IFM) also submit a bid for a matching quantity of reliability capacity in the residual unit commitment (RUC) process[35] of the day-ahead market.

[35] *See* description of RUC in the CAISO EDAM Final Proposal at page 84, available at: http://www.caiso.com/InitiativeDocuments/FinalProposal-ExtendedDay-AheadMarket.pdf

6. At the time, the uncertainty requirements for Net Load (Load forecast Demand – Renewable Forecast) has not been shared with stakeholders. PGE will evaluate these requirements for PGE's portfolio.

We will continue to evaluate the mechanics of how the Resource Sufficiency Requirement is implemented as the details of the EDAM methodology are finalized.

Q. What are the expected transmission impacts from participating in the EDAM?

A. The transmission rights associated with delivering energy to meet the RSE are required to be made available ahead of participating in the day ahead market, by 10:00 a.m. This design seeks to maximize the amount of transmission available in EDAM, enabling EDAM to optimally transfer energy to meet participants' loads. However, this design could impact the COB margins as CAISO would control the transmission rights available to the market by 10:00 a.m.

Q. Please discuss the GHG accounting and reporting.

A. The design of the EDAM market has finalized the initial GHG modeling and report for the EDAM go-live date. The following are the highlights for the GHG implementation:

1. Modeling the geographic boundary of a GHG regulation area to reflect state-level policies.
2. Supporting bid adders for multiple GHG regulation areas via carbon cost.
3. Limiting import and export to limit secondary dispatch.
4. Limiting secondary dispatch through a new counterfactual approach to reflect improved GHG accounting.

Item No. 2 is not easily applicable in Oregon due to the fact that Oregon law does not allow for use of carbon pricing. The GHG modeling uses carbon pricing rather than emission limits in the plant dispatch. For EDAM GHG accounting and reporting as currently proposed it is essential to include carbon pricing in the plant dispatch to meet Oregon's emission goals, similar to the states of Washington and California.

Q. Do you expect cost/benefit impacts on the NVPC forecast associated with a potential participation in the EDAM?

A. As previously mentioned, PGE is still evaluating and has not yet decided with regards to participating in the EDAM market. Therefore, it is premature to estimate any EDAM impacts on the NVPC forecast although it is likely that NVPC modeling may need changes in the future to address market complexities associated with the EDAM. Additionally, one of the potential benefits identified for EDAM is that the market model uses hourly day ahead prices compared to current block trades for HLH and LLH. As MONET already uses hourly market prices this potential benefit is already reflected within PGE's NVPC forecast.

4. QF Pass-Through Mechanism

Q. Why are you proposing a QF Pass-Through?

A. Our proposal for a QF Pass-Through is inspired by Staff's recommendation in our 2023 AUT (UE 402). In the 2023 AUT proceeding Staff recommended that the Commission adopt a QF pass-through mechanism that would resolve any issues of over or under forecasting QF generation within NVPC forecasts. The mechanism would address cost uncertainties related to market prices for QF replacement power or generation surplus and ensure appropriate sharing of risk associated with QF generation between PGE and its customers. Given the obligation under federal and state law to purchase electricity produced by small power producers and co-generators, a QF pass-through mechanism represents a reasonable approach to address the volumetric uncertainty and price risks for replacement power associated with QF generation. Staff provided their proposed mechanism in Staff Exhibit 500.[36]

Q. How do you propose the QF Pass-Through mechanism to function?

A. We propose the following mechanism, which follows Staff's proposal in UE 402, with certain modifications:

- PGE would forecast QF costs based on the rolling average of the most recent full years of QF generation, up to three historical years.
- PGE's actual QF costs would be compared to the forecasted costs,
- The resulting surplus or deficit would be passed through the following AUT proceeding as either a charge or a refund to customers based on the difference between contract price collected from customers in the NVPC forecast and the day-ahead Mid-C power price. Additionally, this would capture any potential situation in which the QF pays PGE delay damages if the QF did not meet the contractual online date.
- The price for the Mid-C would include a weighting of the light load and heavy load hours by the respective hours in the day

Q. How would the QF pass-through mechanism be applied to 2024 QF generation?

A. The mechanism would be applied as follows:

1. During the 2024 GRC: PGE determines the 2024 QF generation forecast for currently operating QFs based on the rolling average of the most recent full years, up to three historical years. PGE adds any new QFs expected to come online in 2024.

[36] *See* Docket No. UE 402, Staff Exhibit 500 at 10, available here: https://edocs.puc.state.or.us/efdocs/HTB/ue402htb123740.pdf

2. Before December 31, 2023: PGE submits a request for deferred accounting reauthorization under UM 1988, adjusting the QF track and true up deferral to ensure all QF generation and cost is subject to deferred accounting.
3. After the end of 2024, PGE will compare forecast QF generation with actual QF generation and will calculate a collection or refund to customers based on the following:
    a. If QF forecast generation > Actual QF generation for any particular QF: replacement power will be valued at the difference between the QF contract price and the actual day-ahead on-peak and off-peak Mid-C market settled price; and
    b. If QF forecast generation < Actual QF generation for any particular QF: surplus power will be valued at the difference between the QF contract price and actual settled day-ahead on-peak and off-peak Mid-C power price.
4. Any collection or refund resulting from having to replace QF power with market purchases or having surplus QF generation compared to the forecast will be amortized in the 2026 NVPC forecast to be processed during 2025.

Q. Should the Commission adopt a QF pass-through mechanism, would PGE continue to implement the QF track and true-up mechanism?

A. No. The QF track and true up mechanism would no longer be necessary since any power cost variance associated with QFs under or over generation would be addressed by the QF pass-through mechanism. Therefore, PGE would stop tracking and trueing up new QFs coming online in the test year.

IV. Forthcoming Updates

Q. Does PGE expect to update any items in future filings in this proceeding?

A. Yes. We expect to update plant parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; historical COB trading data; CCA forward price curve; Wheatridge REC monetization benefits; and make any errata corrections to this initial filing in the April 1 filing. This is standard practice during a GRC proceeding.

V. Comparison with 2023 NVPC Forecast

Q. Please restate PGE's initial 2024 NVPC forecast.

A. The initial forecast is $860.1 million.

Q. How does this 2024 NVPC forecast compare with the 2023 forecast used to develop NVPC in UE 402 and approved in Commission Order No. 22-427?

A. Based on PGE's final updated MONET run for the 2023 test year, the NVPC forecast was $730.2 million, or $35.8 per MWh. The initial 2024 forecast is $860.1 million, or $40.8 per MWh, which is approximately $5.0 per MWh more than the final forecast for 2024.

Q. What are the primary factors that explain the increase in NVPC forecast for 2024 versus the NVPC forecast for 2023 in UE 402?

A. Table 9 below lists changes in NVPC by factor between 2023 and 2024.

Table 9
Forecast Power Cost Difference 2023 vs. 2024 ($ Millions)

Factor	**Effect ($M)**
Hydro Cost and Performance	$ 9.3
Coal Cost and Performance	$ 0.8
Gas Cost and Performance	$ 62.4
VER Cost and Performance	$ 24.8
Contract and Market Purchases	$ 14.8
Market Purchases for Load Increase	$ 14.3
Transmission	$ 3.4
Total	**$ 129.8**

* *Numbers may not total due to rounding.*

The primary factors contributing to the increase in NVPC include: 1) an increase in costs due to higher thermal plant dispatch expected in 2024 at higher fuel costs, 2) increased costs associated with market and contract power purchases, 3) increased market purchase volumes and costs and reduced market sales volumes and benefits due to an expected increase in customer loads, and 4) reduced market sales benefits due to carbon obligations under the Washington Cap-and-Invest program.

VI. Qualifications

Q. Ms. Schwartz, please describe your qualifications.

A. I received a Bachelor of Arts degree in Accounting from the University of Oregon in 2013. I have worked at PGE in various finance and accounting roles since May 2019. Currently, I manage the MONET modeling team in addition to a team of accountants. Prior to PGE, most of my experience was in the audit practice of a Big Four accounting firm. I am a Certified Public Accountant in the state of Oregon.

Q. Mr. Outama, please describe your qualifications.

A. I received a Bachelor of Science degree in Accounting from the University of Washington in 1996. I have over 22 years of experience with PGE working in accounting, financial planning, risk management, structuring and origination, and power operations. I have been involved in originating and pricing of custom products, asset acquisitions, as well as ad hoc project management including the 2012 Request for Proposals on behalf of PGE's customers. My current position is Senior Director Energy Supply. Prior to this I held positions as General Manager of Power Operations, Director of Financial Forecasting & Planning and Manager, Origination, Structuring and Fundamental Analysis.

Q. Mr. Cristea, please describe your qualifications.

A. I received a Bachelor of Arts degree in Regulatory Economics from the University of Calgary, Alberta, Canada. I have been employed at PGE in the Rates and Regulatory Affairs department since 2016. I have served as a witness to or lead regulatory analyst for numerous PGE ratemaking, rulemaking, and policy regulatory proceedings such as general rate cases (UE 319, UE 335, and UE 394), annual power cost updates (UE 359, UE 377, UE 391, and UE 402), and power cost adjustment mechanism filings (UE 346, UE 362, UE 381, UE 395, and UE 406). Previously, I worked as an Operations Coordinator for Enterprise Holdings in Calgary, Alberta, Canada, overseeing the operations of approximately 50 car-rental offices. Prior to that, I owned and managed a construction business in France.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
301	List of MFRs per Commission Order No. 08-505

Minimum Filing Requirements
July 7, 2008

General

The Minimum Filing Requirements (MFRs) define the documents to be provided by PGE in conjunction with the Net Variable Power Cost (NVPC) portion of the Company's initial (direct case) and update filings of its General Rate Case (GRC) and/or Annual Update Tariff (AUT) proceedings.

The term "Supporting Documents and Work Papers" as used here means the documents used by the persons doing the NVPC forecasting at PGE to develop the final inputs to Monet and the final modeling in Monet for each filing. This may include such items such as contracts, emails, white papers, studies, PGE computer programs, Excel spreadsheets, Word documents, pdf and text files. This will not include intermediate developmental versions of documents that are not used to support the final filing. Documents will be provided electronically where practical.

In cases where systems change or are replaced in the future, such as BookRunner, the MFRs will continue to provide substantially the same information as provided in PGE's 2009 GRC (UE-198).

PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at the time of the filing, rather than these parties having to wait for the OPUC to approve the protective order in the case.

Delivery Timing

In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:

- Summary Documents (Items 1-6)
- Modeling Enhancements and New Item Inputs (Item 14) – not applicable in AUT year
- Miscellaneous Item 15d - re: Testimony and Exhibits provided on the CD

The remainder of the Direct Case Filing MFRs will be delivered with the initial filing if practical, or no later than fifteen days after the filing (e.g. March 15 in a GRC year, April 15 in an AUT year).

For all update filings, Update Filing MFRs will be delivered with the update filing with the following exception. For the April 1 GRC Update Filing in a GRC year, the delivery of Item 23 will be made with the filing if practical, or no later than fifteen days after the filing (e.g. April 15).

Direct Case Filing

Applicability

- Applies to GRC Initial Filing (e.g. February 28) in a GRC year
- Applies to AUT Initial Filing (i.e. April 1) in a non-GRC year

Summary Documents

1. Monet model for the final step
2. Hourly Diagnostic Reports for the final step
3. Step Log showing NVPC effects of modeling enhancements, modeling changes, addition of new items or removal of items from the prior year rate proceeding (GRC or AUT), and other major updates that PGE believes the parties would want to see identified separately, such as updating the hydro study.
4. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
5. Executable files, any other files needed to run Monet, and installation instructions
6. Identification of the operating system PGE uses to operate Monet

Supporting Documents and Work Papers for the Following

7. Forward Curve Inputs. Consists of:
    a. Electric curve extract from Trading Floor curve file
    b. Gas curve extract from Trading Floor curve file
    c. Canadian/US Foreign exchange rate (F/X Curve) from Risk Management
    d. Model run for hourly shaping of monthly on/off-peak electric curve (Lydia Program)
    e. Oil forward curve
8. Load Inputs. Consists of:
    a. Monthly load forecast from Load Forecast Group
    b. Hourly load forecast from Load Forecast Group
    c. Copy of the loss study used by Load Forecast Group to develop busbar load forecast
9. Thermal Plant Inputs
    a. Capacities
    b. Heat Rates
    c. Variable O&M

       This includes any other cost or savings components modeled as part of Variable O&M, such as incremental transmission losses, SO_2 emission allowances (emission allowance $/ton price forecast, plant emission factors lb/MMBtu), etc.
    d. Forced outage rates
    e. Maintenance outage schedules and derations
    f. Minimum capacities
    g. Operating constraints
    h. Minimum up times
    i. Minimum down times
    j. Plant testing requirements
    k. Oil usage volumes
    l. Coal commodity costs
    m. Coal transportation costs
    n. Coal fixed fuel costs classified as NVPC items

       Includes items such as: Colstrip Fixed Coal Cost and the following Boardman costs: Rail Car Mileage Tax, Coal Sampling, Rail Car Lease, Rail Car Maintenance, Trainset Storage Fee, and Coal Car Depreciation
10. Hydro Inputs
    a. Monthly energy for all Hydro Resources

       This will include the results of PGE's most current study using the Pacific Northwest Coordination Agreement (PNCA) Headwater Benefit Study. Note that this program is not the property of PGE and should be obtained from the Northwest Power Pool. Provide the PGE version of the PNCA model inputs, so that if the Parties obtain the PNCA model, they would have the inputs needed to reproduce PGE's study.
    b. Description of logic for hourly shaping where applicable
    c. Usable capacities where applicable
    d. Operating constraints modeled
    e. Hydro maintenance derations
    f. Hydro forced outage rates (not currently modeled)
    g. Hydro plant H/K factors
    h. Spreadsheet demonstrating how the hydro energy final output from the PNCA study is adjusted to arrive at the monthly energy output on the PwrAEOut sheet
11. Electric and Gas Contract Inputs
    a. Copy of contract for each long-term (5-year or greater term) or non-standard power contract modeled in Monet.

       For some contracts, this may consist of a term sheet rather than a full contract, depending on what was deemed reasonably necessary by the power modelers to model the contract in Monet.
    b. BookRunner extracts for the test year of:

       Electric Physical Contracts
       Electric Financial Contracts
       Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

c. Copy of each firm gas transportation or storage contract modeled in Monet
d. List of the PURPA QF contracts modeled in Monet
e. List of the long-term (5-year or greater term) or non-standard contracts modeled in MONET that were not included in PGE's most recent GRC or AUT.
f. Gas transportation input spreadsheet or its successor/equivalent
g. Website snapshots input to the gas transportation spreadsheet
h. Other Supporting Documents and Work Papers for contracts modeled in Monet, including any items showing on the Monet Cost and/or Energy Output reports not covered above. Could include structured contracts, option contracts, etc.
i. Coal contracts: Covered above under Thermal Plant Inputs
j. Amortizations of regulatory assets or liabilities modeled in the Contracts section of Monet

12. Wheeling Inputs
    a. Supporting Documents and Work Papers for all wheeling items modeled in Monet
13. Wind Power Inputs. Includes but not limited to:
    a. Monthly energy
    b. Hourly energy
    c. Maintenance
    d. Forced outage rates
    e. Integration costs, royalties, other costs and elements modeled
14. Modeling Enhancements and New Item Inputs
    a. Supporting Documents and Work Papers for all modeling enhancements and new items modeled in Monet.
    b. Includes modeling or logic changes, changes to the methodology used to compute data inputs or other type of enhancement to the Monet model.
    c. Modeling revisions, refinements, clean-ups etc. that do not affect NVPC under any conditions will not be considered to be modeling enhancements.
15. Miscellaneous
    a. Line Item Adjustments to Monet such as OPUC orders, settlement stipulations, others
    b. Identification of all transactions modeled in Monet that do not produce energy
    c. Items in Monet not covered elsewhere above
    d. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

<u>Historical Operating Data</u>

16. Hourly extract of data from PGE's Power Scheduling and Accounting System showing actual hourly energy values for the most recent Four-Year Calendar Period of the following:
    a. Generation from each coal, gas, hydro and wind generating plant modeled in Monet. Note that Colstrip Units 3 and 4 generation is aggregated in PGE's system, and the Mid-C contract generation is similarly aggregated.
    b. Long-term (>5 years) electric contract purchases, sales and exchanges modeled in Monet.
17. Table showing the actual monthly generation of each PGE coal, gas, hydro and wind generating plant modeled in MONET, from the period 1998 through the last calendar year.
18. Monthly compilations of actual NVPC produced by PGE for the most recent calendar year.

Update Filings

19. Monet model for the final step
20. Hourly Diagnostic Reports for the final step
21. Step Log showing effect on NVPC of each update step since the last filing
22. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
23. For each Monet update step:
    a. Text description of update, including identification and location of input changes within Monet.
    b. Excel file containing Monet standard output reports (PwrCsOut, PwrAEOut, PwrEnOut) and PC Input sheets.
    c. Supporting Documents and Work Papers for the update step
24. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Power Cost Adjustment Mechanism (PCAM)

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Brett Sims
Darrington Outama

February 15, 2023

Table of Contents

I. Introduction

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

A. My name is Brett Sims. My position at PGE is Vice President, Strategy, Regulation and Energy Supply. My qualifications appear at the end of PGE Exhibit 100.

My name is Dee Outama. My position at PGE is Senior Director, Energy Supply. My qualifications appear at the end of PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to propose modifications to the current power cost adjustment mechanism (PCAM) and provide support for Commission approval of our proposed framework.

Q. What has changed that necessitates modernization of the PCAM?

A. The policy, operating, and market environment is markedly different today than it was 15 years ago. The existing PCAM structure and principles guiding it do not reflect the realities of the current and expected power cost environment. As a result, the PCAM no longer provides proper incentives, aligns fundamental interests, or fairly balances risks and benefits. Momentous new policy mandates require a rapid and essential transformation of the electric system and the energy PGE supplies to our customers. Continued progress towards achieving Oregon's and PGE's ambitious decarbonization targets is critical to address the urgent climate imperative. Specifically, foundational changes have occurred in three areas:

1) In response to policy changes, a massive transition of the resource portfolio for PGE and the entire Western region is underway and will continue. This transition has led to substantial reductions in baseload dispatchable generation and even larger additions of

variable renewable energy resources. As a result, regional capacity is increasingly constrained, with more frequent and acute resource scarcity and reliability risks.

2) Extreme energy market price levels and volatility due to increasing frequency of climate-change driven severe weather and load events, and geo-political disruptions that are beyond PGE's ability to control or substantially mitigate.
3) Advancements in organized markets that increasingly directly and fully capture the benefits of portfolio and market optimization, as well as regional diversity advantages which in the past could only be realized through PGE's power and market operations efforts.

The PCAM mechanism must be updated to reflect these foundational changes in conditions and priorities, while abiding to the key principles of providing proper incentives for cost management, aligning interests, and fairly balancing risks and benefits. Doing so will support our collective ability to deliver a safe, reliable, affordable, and clean energy future for PGE customers.

Q. Please describe further the effect of these changes on the risk profile that exists today.

A. PGE and our customers now face a current and future state of increasingly unpredictable conditions that amplifies energy market and power cost volatility and outcomes. This level of uncertainty exceeds the normal utility business risk contemplated when the PCAM was originally developed and implemented.

Many of the risks associated with these transitions are beyond our control or ability to materially influence, and the tools to mitigate impacts are often limited. Further, evolving organized wholesale markets (e.g., Energy Imbalance Market, Extended Day-Ahead Market) are (or will) provide substantial benefits to customers but are also reducing PGE's ability to independently affect market operations and economic outcomes. At the same time, we remain an essential service provider with an obligation to provide reliable power to our customers, even during the most severe conditions where electric demand and energy market prices more frequently reach extreme levels. We recognize that these are the times when our customers rely on us the most, and our responsibility to deliver reliable service must be our highest priority.

Q. Why is it critical for the Commission to approve changes to the PCAM structure now?

A. It is critical that the Commission act with urgency to approve modifications to the PCAM structure now. Any delay in taking steps to modernize the PCAM will: 1) impair PGE's ability to implement changes to physical and market operations to achieve continued progress towards critical decarbonization mandates; 2) fail to resolve conflicts for meeting upcoming regional Resource Adequacy (RA) standards; and 3) jeopardize PGE's financial stability and ability to raise the significant capital necessary to transform our power supply portfolio and electric grid at the lowest cost and risk.[1]

It is vital to implement PCAM changes today to provide time to plan, implement, and adapt ahead of upcoming deadlines for new mandates. These milestones include: 2030 decarbonization targets; Summer 2025 Western Power Pool Western Resource Adequacy Program (WRAP) binding RA participation; and the likely near-term implementation of a regional day-ahead energy market. Moreover, acting now is vital to meet the needs of our customers and communities.

[1] *See* PGE Exhibit 1000, Section II. A., at pages 3-4, and Section IV. C., pages 68-71, for discussions regarding how the current PCAM structure is viewed by rating agencies and investors.

Q. What PCAM structure do you propose?

A. We propose the following PCAM modifications:

1) Remove the current PCAM deadbands and share all prudently incurred annual Power Cost Variances[2] (PCV) between customers and PGE at a 90/10 ratio.
2) Recover or refund prudently incurred PCV with no application of an earnings test to such variances.
3) Collect or refund 100% of incremental/decremental Net Variable Power Costs (NVPC) prudently incurred during qualifying Reliability Contingency Events (RCEs) outside of the PCAM.
4) Establish a +/- 2.5% rolling cap on customer price changes year over year with amounts beyond the cap rolling to the next year subject to either continued amortization in customer prices or netted against future PCAM credits.

Q. Is PGE's proposed PCAM structure consistent with fundamental principles of cost-of-service regulation practiced throughout the country?

A. Yes. PGE's proposed PCAM structure more closely aligns with power cost recovery mechanisms that exist elsewhere which provide for a more appropriate balancing of risks between customers and the utility. Further, it aligns our collective interests in prudently managing our existing and future portfolio to keep costs as low as possible while we decarbonize and maintain reliable service.

[2] 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.

Q. How does PGE's proposed PCAM structure align interests and fairly balance risks and benefits of power cost outcomes for customers?

A. Removal of the deadbands will more accurately reflect the actual costs and benefits resulting from PGE's portfolio and market operations. With a deadband, customers forgo opportunities for potential refunds when costs fall below the baseline established in rates. Further, the removal of the deadband eliminates an aspect of the PCAM structure that negatively differentiates us from other utilities with whom we compete for capital. Aligning the PCAM with power cost mechanisms more commonly applied across the utility industry and in other regulatory jurisdictions will allow customers to benefit from our ability to execute decarbonization targets more effectively and affordably. Our proposal for an RCE mechanism is focused on addressing reliability risk, which will help to ensure our ability to deliver service to our customers during the most critical times. Finally, our proposal for smoothing and netting any credit balances against amounts owed significantly reduces power cost variability while supporting customer price stability over time.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have three sections. In Section II, we discuss the structure of the current PCAM, how climate change and related policies have greatly altered the regional energy supply, and the impact those changes have had on power costs and PGE's ability to manage them. In Section III, we detail the previously established principles for the PCAM and recommend that the principles be updated to reflect the current policy and operating environment, and we describe our proposed PCAM structure and how it is consistent with the new PCAM principles recommended. Finally, we summarize our arguments and provide a conclusion in Section IV.

II. Changing Power Operations Environment

A. Current Power Cost Framework

Q. Please describe how PGE currently recovers its NVPC.

A. Each year PGE forecasts power costs for the following year, identified as the test-year. The initial forecast is based on known inputs which are updated throughout the year with final updates occurring in mid-November.[3] The costs are then collected through an Annual Power Cost Update Tariff (AUT), Schedule 125, beginning on January 1 of the test-year. Once the test-year is complete, the actual, prudently incurred power costs for the year are compared to the forecast established in the AUT to determine the Power Cost Variance (PCV) for the year, which is adjusted to actual loads.

The PCAM framework is then applied to the PCV to determine if there are any amounts to collect from, or refund to, customers through the PCAM tariff, Schedule 126, as described in more detail below.

Q. How does PGE build its power cost forecast that determines the price charged to customers during the year?

A. The AUT uses MONET, which is an energy-focused market dispatch model, to forecast NVPC. The forecast includes simplifying and normalizing assumptions for energy that must be made in modeling the power system. As with any forecast, projected costs never match the actual costs incurred. Further, as we will describe in more detail later in this testimony, changes in our operating environment have, and will continue, to substantially increase the variability of actual power cost outcomes from forecasted amounts.

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[3] *See* PGE's Schedule 125 Tariff for a full description of the dates and inputs updated during each year.

Q. Under what circumstances does the current PCAM construct allow for a refund or collection of the PCV?

A. The PCAM allows for collection from, or refund to, customers of the PCV subject to power cost deadbands, sharing, and earnings deadbands. First, PGE applies the power cost deadbands. Any differences within the range of -$15 million to +$30 million do not result in a sharing with customers. This means that PGE first retains up to $15 million of below budget costs and absorbs up to $30 million of above budget costs before any sharing occurs.

If there are amounts outside of the deadbands, PGE then applies a 90/10 sharing criteria. The total amount eligible for collection from, or refund to, customers would be calculated as 90% of the amount outside of the deadbands. After determining the total eligible collection or refund, an earnings test of +/- 100 basis points is applied to determine how much, if any, of the final PCV should be collected from or refunded to customers.

If there is a collection from or refund to customers, this amount is then posted to PGE's PCV account where it will accrue interest at PGE's authorized rate of return until the Commission approves amortization.

Q. What led to the adoption of this structure?

A. This structure was adopted for PGE in 2007 through Commission Order No.07-015. In 2006, PGE filed an application (Docket No. UE 180) with the Commission requesting 90/10 sharing of prudently incurred PCVs. Ultimately, the Commission adopted the current mechanism on the premise that it must be limited to PCVs that exceed those considered part of normal business.

Q. Are circumstances the same now?

A. No. Sixteen years later, the circumstances to which PGE is exposed have changed significantly with increasing frequency of severe weather and load events that result in driving up market prices and creating extreme volatility. PGE is facing a current and future state where we are expected to absorb power cost variability that goes far beyond the Commission's original notions of normal utility business risk.

Q. What concerns do you have regarding the construct of the PCAM?

A. We have concerns about the earnings test, which will be explained in detail in Section III. We also find that the deadband construct does not promote the appropriate incentives for setting annual power cost forecasts.

Q. How do deadbands fail to promote appropriate incentives for setting power cost forecasts?

A. The existence of the deadband construct motivates parties to act in their own self-interest and not consistent with a key objective of the AUT process: to as accurately as possible predict power needs for the coming year and to include in rates the forecasted costs for reliably serving customers. If parties in the AUT docket know that $30 million of actual power costs above what is collected in the AUT will not be shared with customers, they are less motivated to identify a realistic NVPC forecast and procure the least cost resources and appropriate mitigations (hedges) to reliably meet expected need and manage risks, since the impact of any underestimate would likely be absorbed in the deadband. Parties' incentives for pursuing accuracy in NVPC forecasts and price mitigation measures that better manage power cost and reliability risks would be enhanced by a structure where actual prudently incurred power costs are recovered through the PCAM. The current PCAM deadband structure detracts from the goal of effective portfolio management to serve customers, and instead incentivizes Parties to reduce the amounts included in the AUT, even when the costs are for reliability and/or market price risk mitigation.

The situation is not a one-sided issue. Parties likely perceive that PGE is also motivated to overstate expected NVPC in the AUT to benefit from the opportunity to achieve below budget actual power costs and the potential to keep $15 million collected in customer prices. These incentives are misaligned and increase the likelihood of incorporating power costs in the AUT that do not reflect the true anticipated cost and risk conditions. Removing the deadbands takes the focus back to where it rightfully should be—not the application of a forecast method, but the prudence of the actions leading to actual incurred costs.

Q. Why is now the right time to remove the deadbands and alter the PCAM structure?

A. We are in a time of major transformation that is creating volatility in the energy markets. The Commission identified it best in its 2023-2025 Strategic Plan when it recognized 'Adaptability' as one of its values. As the Commission astutely recognized within its own Goal No. 1—which identifies using regulatory tools to effectively balance interests and ensure utility service is reliable—there have been significant recent legislative directions and a rapid energy transition. As the Commission's objective indicates, there is a need to address these transformative changes by adapting its planning oversight and ratemaking processes. The next sections of our testimony provide greater detail of how major policy changes are impacting PGE's resource portfolio and how the PCAM mechanism should adapt to these changes.

B. Changing Resource Mix

Q. What were PGE's primary sources for electricity to serve customers at the time the Commission deliberated on the appropriate PCAM structure in Docket No. UE 180?

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

Q. What policies have been implemented in Oregon since the mid-2000s, and how have they impacted power operations?

A. There have been multiple major policy changes implemented in Oregon since the principles and structure of the PCAM were devised that directly impact and will continue to affect PGE's ability to forecast and manage power cost results. First, in 2007 the Oregon legislature passed Senate Bill (SB) 838 establishing Oregon's renewable portfolio standard (RPS). This legislation required large electric utilities to procure and serve load with an increasing amount of renewable energy, up to 25% by 2025. Second, in 2016, SB 1547 mandated that by 2035, utilities in Oregon would no longer be allowed to serve customers with power generated by coal facilities. In addition, SB 1547 accelerated and increased the RPS requirements to 50% by 2040 and beyond.

Most recently, in 2021, in addition to the application of renewable energy targets, the Oregon legislature passed House Bill (HB) 2021, calling for transformational reductions in greenhouse gas (GHG) emissions from Oregon's electric power sector. HB 2021 requires PGE to reduce emissions to serve retail customers by 80% from a baseline amount[4] by 2030, 90% by 2035, and to eliminate GHG emissions by 2040.

Q. How have these policies impacted the mix of resources in PGE's resource portfolio?

A. These policies have, and will continue to, transform PGE's energy supply portfolio from predominantly high capacity, base load and dispatchable generation (that is, able to turn on and off and ramp to meet customer demand) to a portfolio composed of increasing amounts of non-dispatchable and variable renewable energy resources. The renewable resource additions to PGE's and the region's supply portfolios have been primarily wind generation (and some solar), which presents unique challenges with respect to predictability and coincidence with critical peak load conditions.

HB 2021 is technology neutral, and PGE will comply by reporting total retail GHG emissions to the Oregon Department of Environmental Quality (DEQ) under its current Greenhouse Gas Reporting rules[5] that are at or below the specified emissions targets in the target years. PGE is also required to demonstrate continual progress toward targets. By 2030, PGE needs to reduce emissions associated with retail power served to customers to a level at or below 1.62 million metric tons of CO2e, a significant decrease from the 6.1 million metric tons of CO2e reported to Oregon DEQ in 2021, the last year for which official data is available. To achieve this, PGE anticipates procuring and integrating at least 3,000 MW of new, carbon-free resources and capacity by 2030, while reducing fossil fuel generation and purchases served to Oregon retail customers.[6] This includes reduced output from PGE's own

[4] "Baseline" is the average annual emissions associated with electricity sold to retail customers in 2010, 2011, and 2012 as determined by Oregon DEQ.
[5] *See* Oregon Administrative Rules, Chapter 340, Division 215.
[6] The estimate of additional non-emitting MW will be further refined in PGE's next IRP and CEP filings, expected in March 2023.

thermal plants and specified market purchases for gas or coal as well as unspecified power purchased in the market. Under DEQ Greenhouse Gas Reporting rules, which govern emissions reporting for compliance with HB 2021, all unspecified power is assigned a positive system wide average emissions factor. Unspecified market purchases, therefore, result in reported emissions to Oregon DEQ. To achieve HB 2021 emissions targets, PGE will need to make significant changes to our generation portfolio, operating practices, and how we transact in wholesale energy markets.

Q. Please describe PGE's resource portfolio before and how it has changed.

A. In the early and mid-2000s, PGE's resource portfolio was predominately comprised of thermal and hydro resources and included a negligible amount of contracted renewable variable energy resources (i.e., a total of 100 MW nameplate capacity for: Klondike Wind PPA – 75 MW and Vansycle Ridge Wind – 25 MW).[7] Beginning with the first major policy change in 2007, PGE began to add variable renewable energy resources to meet RPS standards. In total, to date, PGE has added more than 1,000 MW of wind capacity[8] since the early 2000s and additionally contracted for more than 300 MW of renewables from PURPA Qualifying Facilities (solar, wind, and biopower technologies). In 2021, the last year for which official data reported to Oregon DEQ is available, PGE reported that 35% of the energy generated or purchased to serve Oregon retail customers came from non-emitting sources: 20% from hydro and 15% from wind and solar. By 2040, 100% of the generation and purchases serving Oregon customers must come from carbon-free resources. PGE has already taken significant steps to decarbonize its portfolio. In 2020, PGE retired its 556 MW Boardman coal generating plant

[7] *See* PGE's 2017 Integrated Resource Plan, Chapter 2.5 – Non-hydro Renewable Resources at 29-30, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc43haa105740.pdf
[8] PGE added Biglow Canyon (450 MW) between 2007 and 2014, Tucannon River (367 MW) in 2014, and Wheatridge Wind (300 MW) in 2020.

and added 300 MW of nameplate wind generation with the Wheatridge Renewable Energy Facility. In 2022, Wheatridge was expanded to include 50 MW of solar generation and 30 MW of battery storage, becoming the first project to deploy the three clean energy technologies at scale. Reported emissions to DEQ in 2021 were already 24% below HB 2021 baseline emissions.

Q. Did neighboring states also implement policies that have altered the mix of resources used for generating and serving power to consumers?

A. Yes. California and Washington established RPS requirements in 2002[9] and 2006,[10] respectively. Most recently, both California and Washington have implemented aggressive GHG emission reduction requirements. In 2019, Washington passed the Clean Energy Transformation Act (CETA), which requires utilities to eliminate coal-fired generation and commits Washington to GHG emissions-free electricity by 2045. California adopted cap-and-trade regulations in 2010[11] and in November 2022, California released its plans to build out a 100% clean energy grid and achieve carbon neutrality by 2045.

Q. How has the resource capacity stack changed over the last two decades in the Pacific Northwest and California?

A. Between 2001 and 2010, the resource capacity stack in the Northwest Power Pool (NWPP) and the California Independent System Operator (CAISO) regions was largely composed of firm and dispatchable plants fueled by coal, natural gas, and hydro. As provided in Figures 1 and 2 below, starting in the mid-2010s to now, increasing amounts of non-dispatchable,

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[9] The California RPS program was accelerated in 2015 with SB 350, which mandated a 50 percent RPS by 2030.
[10] The Washington RPS program established in 2006 requires investor-owned utilities to be 100 percent GHG neutral by 2030 and 100 percent renewable or zero-emitting by 2045.
[11] California Air Resources Board, Cap-and-Trade Regulation, available at: https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/cap-and-trade-regulation

intermittent renewable resources (wind and solar) were added to the resource stack while dispatchable gas plants and coal plants were retired. This trend is expected to continue through the current decade and beyond.

Figure 1
NWPP Generation Changes by Resource Type

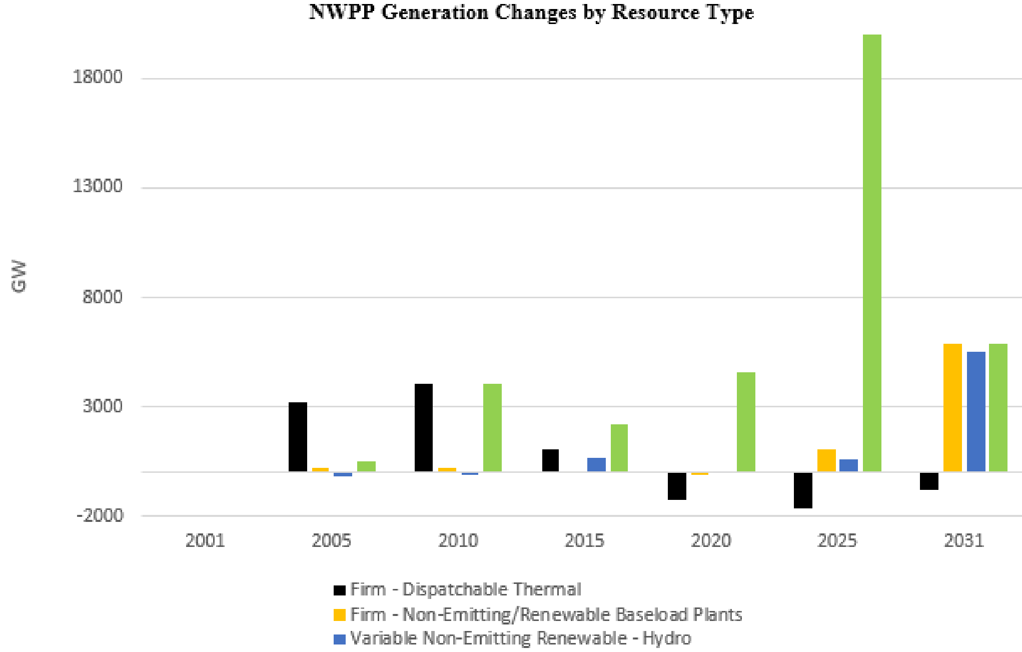
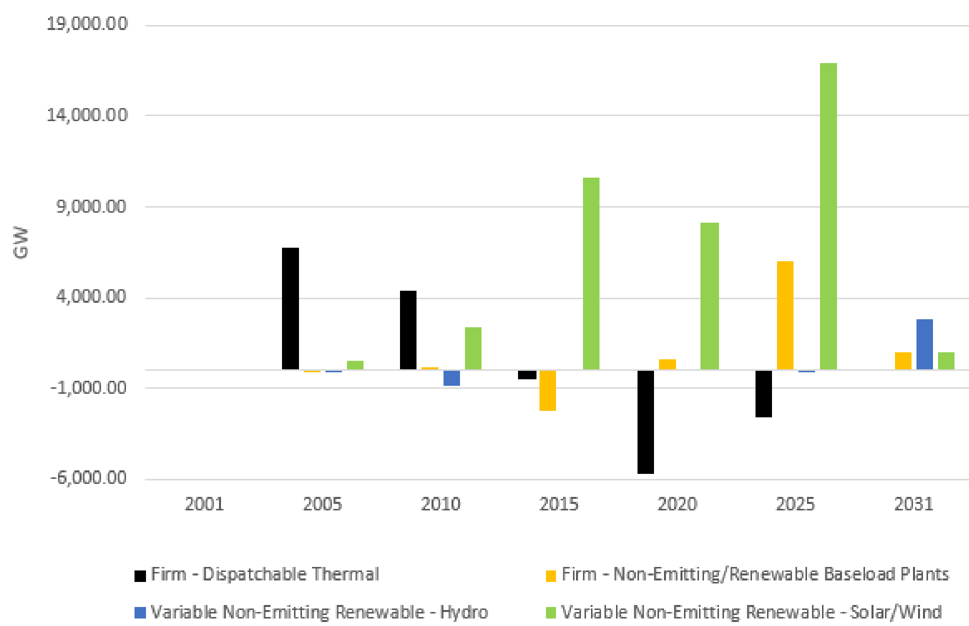


Figure 2
CAISO Generation Change by Resource Type



C. Impact of Climate Change

Q. Has PGE's service territory experienced the impacts of climate change?

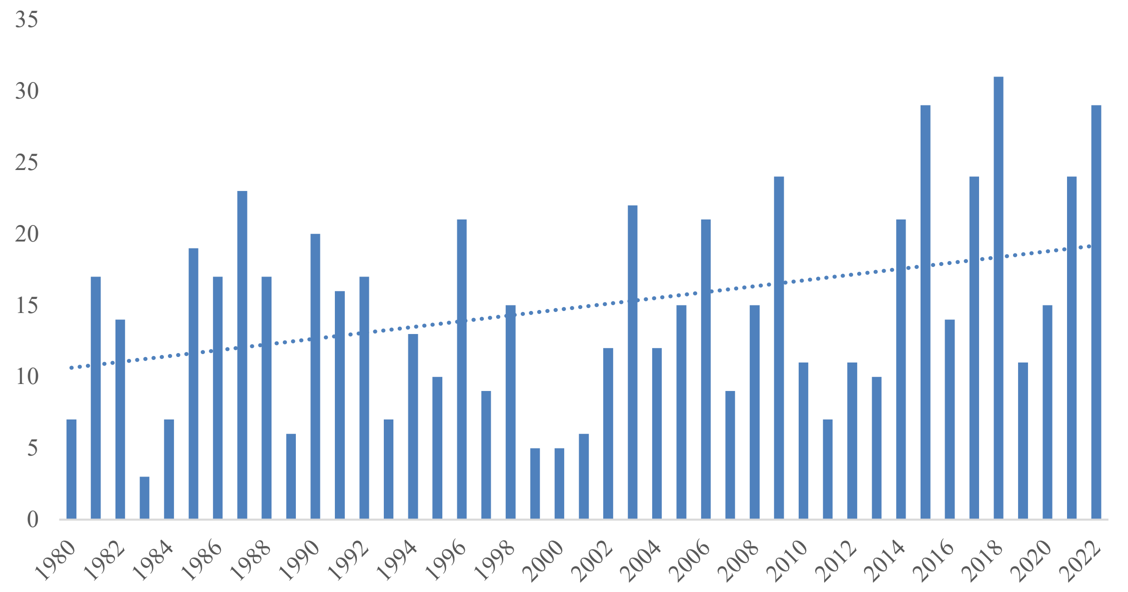
A. Yes. PGE's service territory has experienced the impacts of climate change in several ways. For example, in February 2021, PGE's service area experienced a severe ice storm followed only months later by an extreme heat dome event in June 2021. Figure 3 further demonstrates the changes by showing that there has been an increase in both frequency and magnitude of extreme weather events over the past 40 years in the Portland metro area.[12] These severe weather events in peak months have resulted in a change to energy demand with record-setting system loads experienced in 2021 and 2022 for utilities across the Western Interconnection.[13] In fact, four of the last five summers in Portland have been within the top ten warmest summers over the 80+ year period of measurement, based on PGE's temperature data set going back to 1941. Current predictions indicate that this trend will increase without aggressive action to reduce global carbon-dioxide emission levels over the next approximately 75 years.[14]

[12] Portland International Airport Weather Station, CF6 data set from: https://www.weather.gov/wrh/climate?wfo=pqr

[13] The Western Interconnection is the geographic area covered by the Western Electricity Coordinating Council (WECC).

[14] *See* chart with the global projected temperature increase in: State of the Interconnection Insights and Takeaways 2022, WECC, Figure 6 at page 8, available at: https://www.wecc.org/Reliability/2022%20SOTI%20Final.pdf. *See* also: Predictions of Future Global Climate, UCAR Center for Science Education available here: https://scied.ucar.edu/learning-zone/climate-change-impacts/predictions-future-global-climate

Figure 3
Number of Days with High of 90 Degrees or Greater in Portland Metro Area



D. Changing Wholesale Market Dynamics

Q. What is scarcity pricing?

A. Scarcity pricing refers to extreme price escalations that can occur when market supply becomes tight. Energy markets start to exhibit scarcity pricing when the forward market implied heat rate exceeds the heat rate of the least efficient and highest cost energy resource available in that market. The market heat rate is a calculation of the market energy price divided by natural gas prices for a specific term and location. In addition, as the market transitions from the forward to day-ahead market, volatility around that average forward price must account for new information such as changes in weather, unplanned generation outages, and other event risks, often driving prices higher and at times to extreme levels.

Q. Please explain why the number of scarcity price events is expected to increase as a result of the reduction in firm dispatchable resources.

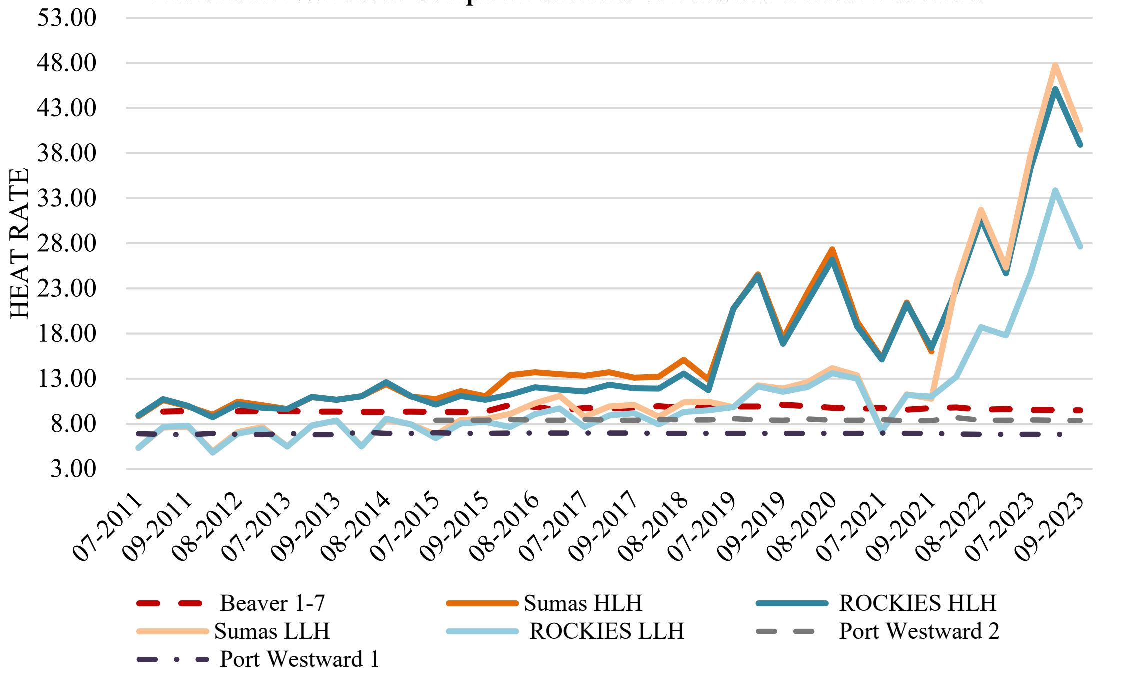
A. Historically, the forward market heat rate[15] has settled at or below the dispatch cost of PGE's Beaver gas-fired generating facility, one of the oldest plants in the region. In the past, the market projected that one of the oldest (least efficient) plants in the region would only be needed in the highest demand month, typically August. It has previously been understood that any load and price excursion would bring Beaver, or a plant similar to the Beaver heat rate, online to meet that incremental energy need.

As provided in Figure 4 below, in recent years, the forward market heat rate has frequently disconnected from the regional energy supply stack during peak summer months. For example, the forward market heat rate increased dramatically, reaching nearly 50 mmBtu/MWh in Q3 of 2023. In contrast, PGE's marginal heat rate units at Beaver is approximately 9.5 mmBtu/MWh, and Port Westward 2 (PW2) is approximately 8.4 mmBtu/MWh. These plants were designed and built to serve primarily as capacity resources to meet peaking demand and for wind-following purposes. Beyond Beaver and PW2, other regional "peaking" gas plants dispatch at roughly an equivalent of a 13 mmBtu/MWh. Any market price above a 13 mmBtu/MWh indicates that all of the thermal plants in the region need to be "on," and additional market supplies must be made available at higher prices and/or demand must be reduced to achieve equilibrium and balance the system. Furthermore, during these times the market is also signaling that any additional demand beyond the average load would have no natural price "ceiling," enabling prices to rise

[15] Calculated based on forward power and gas prices as determined in final historical AUT forecasts. For final NVPC forecasts, the forward power and gas prices as based on the average of the first five trading days in the month of November of the year prior to the test year.

rapidly until demand is met, curtailed, or FERC imposed price caps are reached.

Figure 4
Historical PW/Beaver Complex Heat Rate vs Forward Market Heat Rate



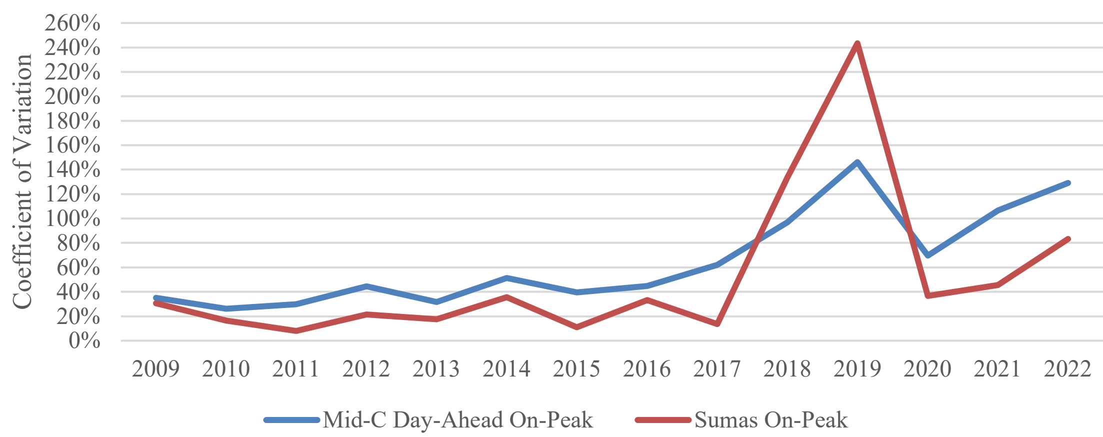
Q. Please provide any additional support that demonstrates the increase in capacity shortages, and, therefore, market volatility and scarcity pricing.

A. PGE, as with most utilities in the Pacific Northwest, transacts power primarily at the Mid-C market hub and natural gas at the Sumas market location. Generation uncertainty due to the proliferation of wind and solar resources has caused increasing Mid-C power market price volatility since the early 2000s to today. Additionally, natural gas price volatility has increased in recent years due to increased demand, pipeline/supply constraints, or low gas storage inventories. Figure 5 below depicts how the Mid-C and Sumas on-peak coefficients of variation[16] increased between 2010 and 2022. The Mid-C electricity on-peak coefficient of

[16] Energy markets volatility is quantified using the coefficient of variation statistical method which measures the relative dispersion of data points in a data series around the mean. The coefficient of variation is appropriate to quantify the annual volatility of Mid-C and Sumas on-peak day-ahead prices and is calculated as the standard deviation of daily on-peak prices divided by the average of daily on-peak prices.

variation increased from around 20-40% in early 2010s to more than 100% in 2021 and 2022 and the Sumas natural gas on-peak coefficient of variation increased from around 10-20% in early 2010s to more than 80% in 2022. As the market price volatility increased, PGE's exposure to market purchases at extreme prices also increased, increasing the challenge of reliably meeting customer demand during peak periods.

Figure 5
Mid-C and Sumas On-Peak Energy Markets Price Volatility



Further, the increase in Energy Emergency Alerts (EEA) issued by Reliability Coordinators (RCs)[17] in the Western Interconnection is further evidence of the increasing difficulties in meeting customer reliability needs across the region.

Q. What is an EEA and what information do you have to support your statement above?

A. Generally, an EEA is a notification to balancing authorities of a potential deficiency in energy for the region to meet consumer loads. When certain reliability criteria are exceeded, the Western Electricity Coordinating Council (WECC) may declare an EEA for the balancing authorities that are part of the Western Interconnection footprint and are parties to the

[17] An RC oversees grid compliance with federal and regional grid standards and can determine measures to prevent or mitigate system emergencies in day-ahead or real-time operations. The RC also provides leadership in system restorations following major events.

Resource Sharing Group, which includes PGE. RC-West is the reliability coordinator of record for PGE.[18] To ensure that all RCs clearly understand potential and actual Energy Emergencies in the Western Interconnection and know what is expected of them during these emergencies, the North American Electric Reliability Corporation (NERC) has established three levels of EEAs: EEA1, EEA2, and EEA3.[19] Please see PGE Exhibit 300, Figure 1 for a depiction of EEAs issued by WECC RCs between 2007 and 2022. In recent years EEAs have been issued primarily due to reliability concerns during more extreme winter and summer weather events, reflecting the climate change driven impacts on the region. As a result, they have often caused significant market disruptions and power operations challenges which affect PCVs.[20] The chart in Exhibit 300 demonstrates that the number and severity of EEAs declared by the WECC RCs increased in recent years. We expect this trend to continue.

E. Consequences of Changes on PGE Power Operations

Q. How have policy changes in Oregon and in neighboring states, in combination with extreme weather events due to climate change, impacted PGE's power operations since the inception of the PCAM in 2007?

A. The policy landscape changes seen in the last two decades within the Western Interconnection (including the NWPP footprint) have significantly impacted the cost and availability of resources that PGE obtains from the wholesale market to meet customer peak demand,

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[18] RC-West is the reliability coordinator of record for 42 balancing authorities (including PGE) and transmission operators in the western United States. As provided in the Reliability Coordinator Procedure, RC-West has "the responsibility and authority to act to address the reliability in the RC Area, in both Real-time and next-day operations, by issuing Operating Instruction to NERC-registered entities to take actions up to and including shedding firm load. RC Operators have the responsibility and authority to direct these actions without obtaining prior approval from higher level personnel within RC West." *See* RC-Procedure No. RC0100 effective June 17, 2022, here: https://www.caiso.com/Documents/RC0100.pdf.

[19] *See* description of each EEA level in Attachment 1, starting at page 11: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

[20] *See* Exhibit 300, Table 3.

especially during extreme weather and load events. These load excursions, coupled with resource intermittency, and somewhat negatively correlated nature of most variable energy resources in the regional energy stack to high demand conditions caused by extreme weather, have stressed regional resource adequacy and exacerbated volatility in the market. PGE's portfolio is no different from the regional wind/load negatively correlated portfolio. As a result, during these "super-peak" demand events, PGE must both serve higher load requirements and replace previously expected wind energy that is generally not available during times of very cold or hot temperatures.

The trend of high volatility and increasing frequency of extreme events and market conditions was particularly evident throughout 2022. During heat events in 2021, the Mid-C on peak day-ahead power market prices settled at more than $500/MWh and in 2022, the Mid-C prices settled at more than $1000/MWh on certain days with weather excursions during the third quarter. Additionally, December 2022 natural gas commodity prices surged to over $50/MMBtu, compared to a forecast of only $5.5/MMBtu assumed in the 2022 AUT NVPC forecast.

These issues are also discussed extensively in PGE's 2022 AUT[21] and 2023 AUT filings.[22]

Q. Does PGE expect these circumstances to persist? If so, why?

A. Yes. PGE expects these circumstances to continue and potentially intensify as climate change drives more frequent severe weather events and we transform the energy system to achieve the decarbonization targets of 2030 and beyond.

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[21] *See* Docket No. UE 391, PGE Exhibit 100, Section III.A, starting at page 10 for 2022 AUT filing here: https://edocs.puc.state.or.us/efdocs/HAA/haa94954.pdf

[22] *See* Docket No. UE 402 PGE Exhibit 100, Section III.A, starting at page 10 for 2023 AUT filing here: https://edocs.puc.state.or.us/efdocs/HAA/ue402haa94826.pdf

With respect to the regional resource mix, the trend of adding variable renewables and removing dispatchable thermal resources will continue and accelerate. For example, in their 2021 Integrated Resource Plan (IRP) (Docket No. LC 77), PacifiCorp has included the expected retirement for most of its coal fleet within the next twenty years. The associated reduction in firm dispatchable coal-fueled generation capacity is approximately 1,300 MW by the end of 2025, over 2,200 MW by 2030, and over 2,400 MW by 2040. Furthermore, PacifiCorp's preferred portfolio also reflects 1,554 MW of natural gas retirements through 2040. PacifiCorp's plans are indicative of firm / dispatchable thermal generation retirement trends across the Western Interconnection. In turn, PGE and other utilities in the NWPP have initiated request for proposals (RFPs) for the acquisition of additional renewable resources to meet GHG reduction targets and state decarbonization policies.

Additionally, PGE's most recent estimate of the resource volumes needed to comply with HB 2021, as provided in its 2021 RFP (Docket No. UM 2166), is approximately 2,500 to 3,500 MW of renewable resources, and 800 to 1,000 MW of non-emitting capacity resources. Many Northwest and California utilities face similar and significant renewable resource requirements whether they are subject to HB 2021, Washington CETA, or California emission reduction targets, and it is expected they will add significant renewable resource volumes to their portfolio.

These changes will continue to drive reductions of firm and dispatchable resources across the region or significantly limit their operations with price and / or output caps placed on GHG emissions, exacerbating regional resource adequacy conditions. This manifests in the form of extreme price volatility as reflected in Figure 5 and increases the number of scarcity pricing events that occur during weather-driven load excursions or other market disruptions.

Q. What actions does PGE take to maintain reliable power for customers when faced with the extreme circumstances described above?

A. We implemented a "No Touch" policy in 2017 that is a part of our "Real-Time Trading Emergency Power Operations Procedures." This policy delineates when power operations employees should restrict discretionary activities to prevent an outage or the limitation of available generation resources. We established this framework to mitigate the inadvertent outage of computer systems and generating plants and to provide clear directives and procedures to a wide cross-functional group of internal PGE departments and personnel, ensuring a singular focus on one goal during contingency events: reliable service for customers.

Internally, PGE refers to these events as "No Touch" contingency events. For clarity within this proceeding, we will refer to these events going forward as Reliability Contingency Events (RCE).

Q. What is a Reliability Contingency Event (RCE) and what leads PGE to call an RCE?

A. PGE declares an RCE when there are concerns regarding our ability to reliably meet the energy needs of our customers or maintain the stability of the electric grid if an unexpected plant or transmission outage or another contingency event were to occur. We declare RCEs when availability of generating facilities and transmission and distribution equipment is at risk or conditions signal the likelihood for curtailments impacting contracted energy and/or reduced liquidity in wholesale markets due to strained system conditions such as unusually high loads, unexpected outages, or other constraints driven by adverse events. PGE calls an RCE to ensure supply sufficiency and continued reliable energy deliveries to customers, and to mitigate the need for an emergency declaration for PGE's balancing authority area (BAA) by RC-West.

Q. Does PGE economically manage costs during an RCE?

A. Only after first addressing the eminent risks to reliable electric service. Although we continuously act to optimize the portfolio and reduce power costs, during an RCE PGE's primary focus is ensuring safe and reliable service for our customers. During an RCE there is also a higher risk of deviation between the load forecasted in the Day-Ahead planning window and the actual (i.e., real-time) system load. Thus, to ensure reliable and least cost energy deliveries during RCEs, we reserve a portion of capacity resources in the Day-Ahead operating window and remove wind production from the real-time, super-peak operating window (i.e., Hour Ending 17 – Hour Ending 22 in summer months). Additionally, during a RCE, we postpone discretionary maintenance, operational changes, or testing on generating plants to reduce the risk of outages and to mitigate the threat posed to system reliability.

Q. Will clean energy targets impact power cost levels and volatility in the future?

A. Yes. As we move toward 2030 decarbonization targets, PGE will be required to incorporate carbon assumptions into our dispatch decisions. Because Oregon requires a cap on GHG emissions from energy serving retail customers, PGE must prioritize reliability and minimizing GHG emissions over the economic dispatch of portfolio resources. This rapid portfolio and operational transition, coupled with increasing frequency of acute conditions, substantially impacts PGE's ability to forecast and manage power costs, particularly during circumstances when the costs and risks of providing reliable service are highest.

Q. How should the Commission think of these and other changes in the context of "normal business risk"?

A. There is simply nothing "normal" about the business risk inherent in operating under today's highly variable and extreme conditions while maintaining reliability and making progress toward achieving decarbonization targets.

Q. How does PGE's PCAM compare to power cost recovery structures elsewhere?

A. Among the 11 states that are entirely in the Western Interconnection (including Oregon), only Oregon and Washington have PCAM structures that require the utility to absorb a substantial portion of prudently incurred power and fuel costs. Two additional states partially in the Western Interconnection (Texas and South Dakota) also do not impose a deadband related to their fuel and purchased power adjustment rates. Thus, 11 out of 13 states in the Western Interconnection [23] provide an opportunity for the utility to recover all prudently incurred power costs or have a sharing/incentive mechanism that allows for the majority of all variances to be recovered or refunded by the utility.[24]

Further, among PGE's financial peer set of 12 utility companies with electric operations across 21 states, only Avista's electric operations in Washington state are subject to a deadband construct. The remainder all have power cost true-up mechanisms that either provide for a full pass through of prudently incurred actual power costs or have a sharing mechanism that recovers or refunds the majority of cost variances.[25] These same trends also hold true nationally with most vertically integrated utilities in the United States having either

[23] The 14th and final state that is also partially in the Western Interconnection is Nebraska. Nebraska does not have any investor-owned electric providers in the state. As a result, we exclude this state from our evaluation here.
[24] Wyoming has the smallest allocation to customers at 80% and Idaho has the highest allocation to customers at 95%.
[25] The 12 peer utility companies include: Allete Inc., Alliant Energy Corp., Avista Corp., Black Hills Corp., Evergy Inc., Hawaiian Electric Industries Inc., Idacorp Inc., Northwestern Corp., OGE Energy Corp, Otter Tail Corp, PNM Resources Inc., and Pinnacle West Corp.

full pass through or sharing mechanisms that provide for recovery or refunds of the majority of variations in power costs. PGE competes for capital with all of these otherwise similarly situated utilities.

Q. What are the consequences of the market changes mentioned earlier in terms of power cost variability and difficulty of forecasting power costs?

A. Collectively, these changes increase the degree of power cost variability and create conditions that become difficult to predict or forecast. The frequency, duration, and magnitude of disruptive events led (and will continue to lead) to higher variability and extreme levels of power cost outcomes around any baseline forecast established initially in rates.

Q. Could the Commission have anticipated this based on the environment and their perspective in 2006 when they were determining the PCAM structure?

A. No. It would not have been reasonable at that time to anticipate the extent of the evolution in policy and market dynamics that pre-dated key pieces of legislation.

Q. Has the PCAM been altered in the last 15 years to recognize how new policies have resulted in a significantly different power operations landscape?

A. No. PGE has advanced its market and operational practices considerably over the same period to maintain reliability and contain costs for customers, but the construct for recovering power costs has not similarly evolved.

Q. Is regulatory policy adaptable to changing circumstances as you describe above?

A. Yes. Regulatory policy can and should adapt to changing dynamics. Changing capacity constraints, load profiles, decarbonization policy, and scarcity pricing necessitate reasons to revisit the original PCAM principles and structure. The conditions and circumstances here require swift and decisive actions by the Commission.

III. PGE's Proposal

A. Updated PCAM Principles

Q. What drives the foundation of the PCAM design?

A. In 2005, the Commission established a set of principles that were envisioned to ensure a well-designed PCAM and an appropriate balance of power cost forecast risk between PGE and customers. Initially, the Commission stated four principles in Order No. 05-1261 in Docket No. UE 165 and reiterated these principles when it adopted the original PCAM for PGE in early 2007 through Commission Order No. 07-015 (UE 180). The Commission subsequently articulated an additional principle when it established a PCAM for PacifiCorp in Docket No. UE 246 (Commission Order No. 12-493).

Q. What are those principles?

A. The five PCAM principles are:

1. The PCAM's application should be limited to unusual events and capture power cost variances that exceed those considered normal business risk.
2. There should be no adjustments if overall earnings are reasonable.
3. The PCAM application should result in revenue neutrality.
4. The PCAM should operate in the long-term to balance the interests of the utility shareholders and ratepayers.
5. The PCAM should provide an incentive to the utility to manage its costs effectively.

Q. Given the transformative changes to energy markets in the West and accelerating impacts of climate change since these principles were adopted, does PGE believe changes to the principles are warranted?

A. Yes. Changes to the PCAM principles are warranted to reflect the dramatically altered policy, operating and market conditions that we encounter today and will face in the future.

Q. What are the new PCAM principles PGE proposes?

A. We propose that the principles reflect the current energy market supply and demand environment, including the increased power cost risk, and support PGE's obligation and commitment to meet Oregon's GHG reduction requirements under HB 2021, while continuing to provide safe, reliable, and affordable electric service to customers. As such, we recommend the first principle and the second principle be consolidated into a new, updated Principle #1 as follows:

Principle #1

The PCAM's application should be limited to unusual events and capture power cost variances that exceed those considered normal business risk.	→	Prudently incurred power costs should be fully recoverable / refundable.
There should be no adjustments if the utility's overall earnings are reasonable.		

As we have already discussed, the normal business risk contemplated at the time these principles were established does not reflect the risk environment PGE faces today. Additionally, after 15 years of treating NVPC in isolation, PGE finds that the current PCAM's earnings test unreasonably limits the ability to recover power costs prudently incurred to serve customers, while also reducing the opportunity for refunds to customers when actual costs are lower. This aspect unduly limits the distribution of cost-effectiveness benefits to customers from operational efficiencies and enhanced market structures (e.g., EIM, EDAM, Regional

Transmission Organization). For example, when power costs are below the baseline, if there are cost overruns elsewhere in PGE's operations that reduce our earnings, an earnings test under the PCAM would eliminate or limit power cost refunds that may be otherwise provided to customers. Additionally, power costs that are largely recovered or refunded dollar for dollar could not be a driving force behind any over earning by the utility. We therefore believe that this principle should be updated to allow for the recoverability and refundability of power costs, while maintaining the rigor and oversight of prudence review.

The principle regarding revenue neutrality was formed with the notion of customer price stability and balance over time. However, as explained above, this principle is out of touch with evolving decarbonization policies, rapidly changing operating conditions, and market drivers and circumstances. Further, this principle adds an unnecessary and unreasonable constraint on power/fuel cost recovery mechanism design when compared to industry norms. For these reasons, we recommend that the principle of revenue neutrality be replaced by a principle that recognizes the importance of managing customer price volatility so that the reasonable recovery of prudently incurred costs does not cause large swings in customer bills.

Principle #2

The PCAM's application should result in revenue neutrality.	→	The PCAM should incorporate reasonable pricing tools to manage long-term customer price volatility.

We recommend that the principle regarding the balance of interests between shareholders and ratepayers remain fundamentally the same and that any new mechanism adopted by the current Commission ensure that this principle is fairly and consistently applied.

Principle #3

The PCAM should operate in the long-term to balance the interests of the utility shareholders and ratepayers.	→	The PCAM should fairly balance the interests of the utility and its customers.

Finally, we recommend that the last principle, incentives to manage power costs, recognize the diminishing influence that the utility exerts over the variability and economic outcome of power costs, particularly as organized market structures continue to evolve and fully capture portfolio optimization benefits (EIM-EDAM-RTO).

Principle #4

The PCAM should provide an incentive to the utility to manage its costs effectively.	→	The PCAM's design should incentivize efficient operations and management of costs that are within the utility's control.

B. Updated PCAM Design

Q. What PCAM structure do you propose?

A. We propose recovery of prudently incurred NVPC subject to the following PCAM that complies with and meets the new PCAM principles we proposed above:

1. Remove PCAM deadbands and allow recovery or refund of all prudently incurred NVPC that are above or below the power costs recovered in base rates, subject to a sharing of variances above and below forecast/budget at a 90/10 ratio between customers and PGE.
2. Recover or refund prudently incurred NVPC with no earnings test.
3. Collect or refund all NVPC prudently incurred during qualifying RCEs.
4. Impose a +/- 2.5% rolling cap on customer price changes year over year with amounts beyond the cap rolling to the next year.

Q. Do you provide an updated Schedule 126 that reflects the PCAM reform proposal?

A. Yes. We provide the updated Scheduled 126 in PGE Exhibit 1308**.** We provide our rationale and justification for each of the proposed design change elements below.

1. 90/10 Sharing

Q. What purpose does the 90/10 sharing feature serve?

A. The proposed sharing mechanism appropriately aligns the interests of PGE and customers, promoting efficient operations and incentivizing effective management of controllable costs. It also recognizes that power costs prudently incurred to provide reliable service for customers should be recoverable. In addition, this feature distributes the benefits of efficient operations, implemented cost reduction measures, and organized market structures to customers more directly and timely. As organized wholesale markets continue to evolve from EIM to EDAM and then to full Regional Transmission Organization (RTO), PGE expects the entirety of cost and risk reduction benefits from portfolio and market optimization will be captured directly through the market structure. Accordingly, the best way to realize and distribute these costs and benefits fairly is through the proposed 90/10 sharing mechanism.

Additionally, as discussed previously, removing the deadbands prevents either PGE or Parties from being motivated to push for an AUT forecast and budget that would over or underestimate true anticipated costs in an effort to benefit from the deadband structure. In comparison, a 90/10 sharing structure allows all involved to focus on the prudence of the actions leading actual power costs incurred to serve customers. Finally, this construct more closely aligns with those found elsewhere in the Western Interconnection, thereby reflecting an appropriate balance of risks and rewards between the utility and customers overall.

2. No Earnings Review

Q. Why do you propose the removal of the earnings test?

A. While we agree that customer prices and PGE earnings need to be just and reasonable, we consider that an earnings test in any PCAM construct does not promote overall efficiency and is not the appropriate tool to fairly balance cost and risk while also ensuring reasonable utility earnings. Therefore, we propose that power costs prudently incurred and necessary to provide reliable electric service for customers be recoverable and not subject to an earnings test. These are expenditures over which PGE will have decreasing ability to influence due to changing external factors and evolving market structures; they are also expenditures that offer no return for risks incurred. Moreover, we are exposed to increasingly extreme market volatility and prices, thus, increased power cost risk that is now inequitably balanced and unfairly borne by PGE.

Q. Please elaborate on the argument that an earnings test within the PCAM construct does not promote efficiency.

A. The earnings test under the PCAM is not an appropriate tool because it allows the recovery or refunding of power cost variations (positive and negative) to be unreasonably impacted by the performance of other operational areas. If PGE does not perform effectively in other areas, our earnings would be reduced, and hence, we would earn a lower ROE. In essence, the structure would allow for potential power cost refunds to be retained by PGE to offset poorer performing operations elsewhere. Similarly, should PGE overperform in other operational areas and earn a higher ROE, it could result in a reduced recovery of prudently incurred power costs necessary to serve customers. Thus, the elimination of the earnings test better aligns interests, appropriately balances risks and benefits, and incentivizes operational efficiency and effective management of controllable costs.

3. Full Recovery of RCE

Q. Why do you propose full recovery of costs prudently incurred during RCEs?

A. As previously discussed, RCEs are invoked when elevated risks driven by weather, market or regional conditions, or other factors pose the potential to jeopardize system integrity and our ability to reliably meet customer needs, and in extreme cases to avoid service disruption. During RCEs, PGE prioritizes reliability by conducting physical and commercial operations to reduce market exposure and ensure adequate reserve capabilities, thereby mitigating the possibility that such events could impair reliability. RCEs can vary greatly from one year to the next and are generally anticipated to increase in frequency due to climate-change driven severe weather and resulting load and market dynamics. Power costs prudently incurred to ensure reliability and serve customer needs during extreme conditions and critical times should be fully recoverable.

Q. Do you propose additional criteria for an RCE to qualify to be treated outside the PCAM?

A. Yes. Since an RCE is called by PGE, we propose additional criteria that are independently verifiable and objective for determining whether such costs qualify for full recovery. These criteria also provide clear signals of potential supply shortages that are independent of PGE actions. Any RCE would qualify for PCAM exclusion and full recovery upon a prudence review if the RCE is called by PGE and, at the same time, two out of three of the following criteria are met:

1) Price: Day-ahead Mid-Columbia index prices exceed $150/MWh.

2) Resource Deficits: PGE is eligible to request or acquire RA assistance through a regional RA program in which it participates.[26]

3) A Neighboring BAA (e.g., BPA, CAISO) has declared an event that indicates impending or realized resource adequacy constraints (e.g., Flex Alerts, Restricted Maintenance Operations, EEA Watch, EEAs, etc.).

Q. Can you foresee a situation where two of the qualifying RCE criteria occur, but PGE does not call an RCE?

A. Yes. For example, it is possible that PGE does not have a resource deficit, but RCE criteria 1 and 3 occur (i.e., power prices exceed $150/MWh and a neighboring BAA like CAISO has taken actions that trigger PGE's proposed RCE criteria). In this scenario it is possible that PGE would not call an RCE if its own resource supply is sufficient to reliably meet expected PGE customer needs.

Q. Does the NVPC forecast capture any cost associated with RCEs?

A. Historically, we have not forecasted costs associated with RCE events. However, we propose MONET modeling updates for the 2024 NVPC forecast that aim to provide an initial estimate of the costs associated with RCE events that PGE incurs in actual operations to ensure energy delivery reliability to meet our load serving obligation. While the number of RCEs and the

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[26] Since June 2021, PGE has participated in the Western Power Pool Interim RA Assistance Program. As a participant in the Western Power Pool Interim RA Program, PGE is eligible to request RA assistance from program participants under two different eligibility conditions (i.e., if either condition exists, PGE can request assistance). The conditions for requesting RA assistance under the interim RA program are: Condition 1: PGE forecasts its peak Balancing Authority (BA) load to exceed the 99th percentile load as determined in the Western Power Pool Interim RA Program; and, Condition 2: A unit in PGE's generation fleet experiences a forced outage and the capacity of the lost unit plus PGE's peak BA load forecast exceeds the 99th percentile load as determined in the Western Power Pool Interim RA Program.

While the current interim RA Assistance Program is expected to expire in June 2023, PGE intends to participate in a successor program once established. If the details of a successor RA program become known during the pendency of this rate case, we will update the Commission accordingly.

duration and magnitude of such events is subject to significant variability, we believe establishing an initial forecast is appropriate to compare to actual experience and to establish a baseline around which the RCE proposal operates. As a result, the RCE feature acts like a true-up of actual power costs incurred compared to the forecast. If the RCE forecast costs are more than actual RCE costs, PGE would refund the difference to customers or potentially apply the credits to offset future period under-recoveries. Alternatively, if RCE forecast costs are lower than actual RCE costs, PGE would recover the difference in prices. Therefore, risks and rewards associated with the costs of RCEs are fairly balanced between PGE and customers.

Q. How will you calculate the actual incremental power costs incurred during RCEs?

A. As previously described, during RCEs we reserve a portion of capacity resources and remove forecasted wind production from the day-ahead market operating window. Incremental power costs incurred during RCEs will be calculated as the difference between the AUT forecasted cost for the highest load days of the month in which the RCE occurred and actual power costs during the event. Additionally, we will consider whether there were any unplanned outages at our thermal plants that occurred after the day-ahead planning window which impacted real-time operations and costs.

Q. How will the variance between actual and forecasted RCE costs be determined?

A. The variance between actual and forecasted RCE costs will be determined by comparing the forecast of RCEs used to set customer prices in the final AUT forecast to the actual RCEs calculated as described above for the year. This variance in RCE costs will then be removed from the PCAM variance for the year to ensure appropriate policy application and avoid any double counting of PCAM and RCE variances respectively.

4. Rolling Cap of +/- 2.5%

Q. Please discuss the +/- 2.5% rolling cap.

A. We propose the application of a +/- 2.5% rolling cap to smooth impacts and mitigate against large single year customer price changes due to power costs. This feature defers amounts that would result in price impacts larger than 2.5% until the following year. Thus, amortization of prudently incurred power costs can occur over a longer period to help provide customer price stability from year-to-year. Further, the remaining balance associated with net amounts in excess of the annual price change limitation can be subject to either continued amortization in customer prices or alternative means of amortization. For example, the Commission could offset amounts owed to the utility with subsequent credit balances established when power costs are below the baseline in rates. In this way the Commission maintains a full suite of tools to manage customer price variability with the rolling cap placing an upper limit on amounts collected in any one year.

IV. Summary and Conclusion

Q. Is PGE less incented to control power costs should the Commission adopt the proposed changes to the PCAM?

A. No. As previously noted, the 90/10 feature of the PCAM proposal provides an appropriate incentive for PGE to effectively manage costs that are within its control. Further, it fairly balances the risks and benefits of power cost variations between PGE and customers. Additionally, all power costs incurred are subject to a prudence review by the Commission. Therefore, power costs can be challenged by stakeholders and be subject to disallowance by the Commission if deemed imprudent, further incenting PGE to ensure cost-effective power operations.

Q. Please summarize your testimony and why it is imperative the Commission act now to modify the PCAM structure.

A. Our common vision for a safe, reliable, reasonably priced, and clean energy future is enabled with the updated PCAM principles and structure we have proposed. This vision is threatened by extreme weather events and increases in volatility of power markets and contingency events that could undermine reliability. At the same time, PGE's and the region's resource mix are shifting toward more non-dispatchable resources to meet momentous decarbonization targets. Additionally, the tools that we have to influence power cost outcomes are increasingly displaced by organized market structures and regional resource adequacy frameworks that drive portfolio optimization decisions and directly capture benefits for customers. It is critical that regulatory policy evolve in recognition of these changes while enabling achievement of our shared goals and commitments to Oregon and our customers. Our proposal provides for a better balancing of risks and rewards associated with power cost variations, aligning with the structures most common among industry peers enabling PGE to compete for capital more effectively, while also providing clear incentives for PGE to operate and manage power operations as efficiently as possible. A failure to act in the near term could undermine PGE's ability to meet the state's decarbonization targets while meeting customer reliability requirements. We urge the Commission to adopt the PCAM principles and structure outlined in our testimony.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Anne Mersereau
Tamara Neitzke

February 15, 2023

Table of Contents

I. Introduction

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

A. My name is Anne Mersereau. My position is Vice President, Human Resources, Diversity, Equity & Inclusion at PGE. My responsibilities include leading PGE's talent strategy including establishing total compensation policies and employee policies, continuing to strengthen the work culture at PGE including driving inclusion and more diversity, managing employee recruitment, development and retention, managing employee relations, and overseeing worker's compensation, health and welfare benefits and wellbeing programs.

My name is Tamara Neitzke. I am the Director of Total Rewards (i.e., Total Compensation and Benefits) in the Human Resources Department at PGE.

Our qualifications are provided at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony presents and explains PGE's key talent management challenges. We describe how PGE's compensation philosophy is designed to address compensation challenges, and we present total compensation costs for the 2024 test year. Total compensation costs include total labor costs, incentive pay, and employee benefits.

Q. What are PGE's expected total compensation costs and cost drivers in 2024?

A. PGE forecasts approximately $560.1 million in total compensation costs for 2024. Table 1 below summarizes the cost and compensation components between 2022 actuals and the 2024 test year.

Table 1
Estimated Total Compensation Costs ($Millions)

Component	2022 Actuals	2024 Test Year	2022-2024 Delta
Total Labor	$428.1	$433.0	$4.9
Incentives	$42.4	$20.3	($22.1)
Benefits	$93.8	$106.8	$13.0
Total Compensation*	**$564.3**	**$560.1**	**($4.1)**

** Numbers may not sum due to rounding.*

The net difference between 2022 actuals and forecast 2024 test year costs is a decrease of approximately $4.1 million. Looking at the components, total aggregate labor costs increase by $4.9 million, or 0.6% annually, due to increases from wage escalations and PGE straight-time labor requirements, which is partially offset by a 30% average annual decrease in contract labor and a 30% average annual decrease to contract labor overtime. Benefits will increase $13.0 million, or 7% annually, due to increases in health and welfare costs as well as increases in retirement benefits, which is partially offset by a 50.5% average annual decrease in our legacy pension plan costs. We explain the changes in more detail in Section III below. See PGE Exhibit 501 for more detail on PGE's total compensation costs.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II: PGE's Total Compensation Philosophy and its Challenges;
- Section III: Total Labor Requirements;
- Section IV: Incentives;
- Section V: Benefits; and
- Section VI: Summary and Qualifications.

II. PGE's Total Compensation Philosophy and its Challenges

Q. Please briefly describe PGE's philosophy on total compensation.

A. PGE's philosophy is to provide total compensation sufficient to attract and retain diverse employees with strong qualifications and skills necessary to provide safe, reliable, clean, and affordable energy to our customers. PGE's culture has evolved to one that is customer-focused and results-driven. To keep prices affordable for customers, PGE actively controls costs by targeting market median conditions for our total compensation program. Our ability to serve our customers and their needs is highly dependent on our ability to attract and retain a skilled workforce.

Q. What are the components of PGE's total compensation?

A. PGE's compensation components include:

- Total Labor: PGE designs its non-union and union wages to target the market median based on company size, geographic market, and job function. Additionally, PGE uses market-based contract labor when beneficial from a project-planning and/or financial-planning perspective.
- Incentive Pay: PGE designs its incentive pay to target the market median and to attract, retain, and reward employees for achieving company and individual performance goals that help PGE achieve its objectives.
- Benefits: PGE provides market-aligned health and welfare benefits. PGE also provides a pension and a 401(k) plan for retirement.[1] PGE strives to maintain a

[1] PGE's pension plan is closed to all new employees. Effective February 1, 2009, new non-union employees were ineligible for the pension plan. Effective January 1, 2012, new bargaining unit employees at Coyote Springs, Carty and Port Westward work sites were ineligible for the pension plan. PGE had previously closed the plan to all other new bargaining unit employees effective January 1, 1999.

benefits package that supports our employees' well-being and balances the features and costs both among employee groups and against what other employers in our employment market, as well as adjacent employment markets with overlapping in-demand skillsets, provide to their employees.

Q. What are the major challenges for PGE's talent acquisition, compensation, and benefits?

A. PGE continues to face four strategic challenges that affect our workforce and compensation philosophy, while recent change has introduced to us a fifth challenge:

1. The need to recruit and retain well-qualified, skilled employees to fill changing and evolving jobs in a competitive marketplace;
2. Developing the pipeline of talent to ensure continuity and improvement in the services we provide through workforce planning;
3. Ensuring that our workforce reflects the diversity of our service area;
4. Managing and controlling our benefit costs while providing benefit packages that attract and retain the well-qualified, skilled employees that PGE needs; and
5. Navigating the above challenges in an inflationary environment the likes of which has not been seen in over 40 years.

A. Talent Acquisition and Retention

Q. Please describe the first challenge – hiring and retaining well-qualified, skilled employees in a competitive marketplace.

A. Changes to the external environment (e.g., customer expectations, infrastructure modernization, energy generation transformation, and enabling technologies) are evolving in a manner that requires PGE to continuously assess and improve the technical skillsets and versatility of our employees. Examples of how these skillsets are evolving include:

- Utilities are implementing new technologies and experiencing fast-paced changes in methods for reliably operating the electric grid with increasing levels of variable energy resources. These technologies and changes require utility personnel, such as power plant technicians and substation operators, to possess broader, more versatile skills.[2] We also have the need for highly niche technical skill sets at an increasing pace, which can be extremely difficult to recruit.
- Senior managers have traditionally possessed deep subject matter expertise built through decades of experience. PGE is increasingly placing a greater emphasis on candidates with strong managerial/leadership abilities along with technical abilities, leading PGE to compete for such leadership talent with both utility and non-utility industries.
- Increasingly complex and integrated systems throughout PGE and increasing need in the areas of cyber, network, and physical security require highly skilled and specialized Information Technology (IT) professionals, who are in demand both within and outside of the utility industry.

Our recruiting challenges for these necessary skills continue to be most acute for several specialties.[3] The regional and national demand for highly skilled workers remains high,[4] allowing these workers to be selective about changing jobs or moving. In particular, for

[2] Including advanced technical, mathematical, and mechanical concepts.
[3] Specialties include (1) senior managers in all areas, (2) engineering, (3) IT security, development, and project management, (4) senior professionals working with data, (5) energy trading and pricing, and (6) skilled trade positions such as power plant control operators, meter-service technicians, and line workers.
[4] Similar to the initial unemployment claims information cited above for the utilities industry, the share of total Oregon claims from the Information Services, Finance and Insurance, and Management fields collectively represent only 3% of the total claims filed from January 1, 2020 through May 29, 2021.

positions in the skilled trades such as journeymen line workers,[5] we find that we must more frequently recruit individuals who require relocation.

Q. Are there additional challenges to hiring and retention that differ from what PGE has faced in the past?

A. Yes. Due in part to advances in technology, the evolution of workplace norms, and in response to the COVID-19 pandemic, more industries and companies are allowing for employees to work remotely. This has resulted in increased competition for highly skilled workers as these workers are able to cast a wider net when exploring and seeking new opportunities. Additionally, due in part to the shift toward hybrid and remote work, along with other factors such as financial compensation and personal fulfillment, a recent PwC survey suggests that turnover at a national level is likely to remain high with one in five professionals planning to resign in the near future.[6] In short, it is getting harder for companies to retain their existing talent. Fortunately, due to PGE's continued focus on retention strategies, PGE's 2022 turnover rate of 10.6%, including retirements, was much less than one in five (or 20%). This, however, is still significantly higher than what PGE has historically experienced. From 2015 to 2021 PGE's turnover rate, including retirements, increased from 6.8% to 11.2% before seeing a slight decrease in 2022, creating more pressure and urgency to address the challenge of attracting and retaining talent in a tight labor market for in-demand skills.

Q. How does PGE approach this recruiting and retention challenge?

A. We approach this challenge in five ways:

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[5] Tradesperson who constructs and maintains electric transmission and distribution lines.
[6] PwC. "PwC's Global Workforce Hopes and Fears Survey 2022." 24 May 2022, www.pwc.com/gx/en/issues/workforce/hopes-and-fears-2022.html.

1. We focus on developing talent internally wherever reasonably possible, for example, by using cross-training opportunities to temporarily fill some senior-level or other hard-to-fill positions. The cross-training provides employees an opportunity to work in a different position and provides management an opportunity to evaluate their potential.
2. It is often necessary for PGE to externally recruit senior-level talent to find individuals with the qualifications and skills required for the position. Recent examples include positions in PGE's IT, Finance and Accounting, Communications, Strategy, and Legal departments.
3. We engage in proactive hiring strategies, engaging with both active and passive candidates using major social media job boards such as LinkedIn and Indeed, as well as niche and diversity recruiting sites, community outreach programs and partnerships, college campus recruiting, onsite and virtual job fairs, online tools and research, and data analytics.
4. With increased competition in the talent marketplace, we are also evaluating open positions for their suitability to support remote and hybrid work arrangements. Relocation of talent, as well as H-1B visa sponsorship for highly skilled, but scarce technical talent, is also a strategy we deploy to secure the talent needed.
5. We regularly benchmark and assess the benefits and wages of current employees to ensure that we are providing a competitive total compensation package that supports retention, while also remaining cost-effective. Recent examples include larger-than-normal wage escalations in 2021 and 2022, and upcoming changes in 401(k) benefits.

B. Development Pipeline

Q. Please describe the second challenge – the development pipeline.

A. Ultimately, our challenge of recruiting and retaining well-qualified, skilled employees is closely related to our second challenge (i.e., the need to develop and improve talent to help PGE meet customers' needs). Currently this is of top concern to PGE, as much of the turnover that PGE is experiencing is happening in key positions, which are better suited for employees who already understand PGE values and procedures. Approximately 100 annual retirements in key positions are projected through 2027. The number of retirements at the senior manager and executive level increases the need for succession planning. Additionally, while skilled trade positions at PGE have not experienced as marked an increase in turnover as other operational areas, PGE works to maintain our skilled trade workforce through the apprenticeship program. PGE is working to minimize the knowledge and skill loss that occur when highly skilled and long-tenured employees retire.

Q. What is PGE's approach to the development challenge?

A. PGE supports employee development through educational assistance, employer-paid access to online educational resources (e.g., LinkedIn Learning), mentoring, and cross-training opportunities. We provide an extensive program of formal and informal training classes to help develop our employees in both subject matter expertise and managerial skills and provide access to outside training when it is cost-effective. In addition to these programs, PGE uses the following workforce planning strategies:

- Strengthening and maintaining our summer hire program that helps to develop the entry-level pipeline of engineering, business, and other professional candidates.

- Continued commitment to our Oregon Bureau of Labor & Industries (BOLI) approved apprenticeship program to train and certify new journey-level positions, which typically takes 4+ years of dedicated training and development.
- Strengthening manager capabilities to identify key growth and development areas for their employees and supporting that development.
- Creating positions that allow high-potential employees to rotate through key development roles throughout PGE.
- Focusing efforts on succession planning, including the identification of tailored methods to recruit candidates with the particular skill sets to fill succession needs.

C. Diverse Workforce

Q. Please describe the third challenge – ensuring a diverse workforce.

A. PGE is committed to employing a workforce that is representative of the communities we serve. A diverse workforce helps PGE recognize and respond more efficiently to the diverse needs of our communities. Embracing diversity, equity and inclusion is core to PGE's values. PGE believes that employee diversity and inclusion have multiple business benefits, including higher levels of employee engagement, more effective customer engagement, and improved employee and safety performance.

PGE's service area grows more diverse each year, while at the same time, we continue to face challenges in attracting well-qualified and skilled employees who match the demographics of our communities, particularly in senior-level leadership and the trades.[7] In our efforts to attract a diverse workforce, we experience heightened competition because

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[7] Trades positions include skilled labor jobs such as lineman and wireman, which require specific and specialized training.

all industries in our service area are also striving to improve the diversity of their respective workforces.

Q. What is PGE's approach to its diversity challenge?

A. PGE first works to create compelling compensation programs and a work culture that attracts talent across the demographic spectrum. Beyond ensuring competitive compensation design, attracting and retaining a diverse group of employees must be supported by creating an inclusive work environment. Potential and current employees look for concrete visible examples of our continuing commitment to diversity, equity, and inclusion. Currently these examples include:

- Building upon previous unconscious bias training for employees by hosting trainings on using a Racial Equity Tool, which empowers employees and leaders to view decisions through the lens of equity;
- Leadership development programs for high potential women, as well as for Black, Indigenous, and people of color;
- Earning the Best Place to Work for LGBTQ[8] Equality by the Human Rights Campaign Foundation for the ninth consecutive year;
- Inclusion in the Bloomberg Gender-Equality Index for the fifth consecutive year; and
- Broadening outreach for incoming pre-apprentices and apprentices.

PGE also continues the work of building a more diverse talent pipeline through developing relationships with educational, workforce, and industry stakeholders. In recent years PGE has collaborated with the Multiple Engineering Cooperative Program and the Civil Engineering

[8] Lesbian, gay, bisexual, transgender, and queer or questioning.

Cooperative Program to develop a diverse workforce that is representative of the communities we serve, and we plan to continue to leverage these programs. As we have found internships to be successful in promoting diversity within our organization, we also plan to increase our efforts in targeting positions for internships utilizing the Emerging Leaders Internship (ELI) program, while simultaneously expanding PGE's internship pipeline for new job functions to further expand and diversify the talent pool from which we are recruiting. We are also developing our workforce to meet ongoing and changing business needs through strategic activities that include career pathing, rotation programs, strategic staffing models, upskilling, and research and development.

D. Health Care

Q. Please describe the fourth challenge – health care costs.

A. Health care benefits have traditionally been a key element of the total compensation program PGE uses to attract well-qualified and skilled employees. Historically, health care costs have risen faster than wages, and current projections suggest that trend will continue. A Willis Towers Watson survey of health care providers suggests that in 2023 North America will experience an increase of 6.5%,[9] which is consistent with projections provided by our health and welfare benefits provider.

Q. How has PGE addressed the overall pressure on health care costs?

A. PGE has taken an active approach to managing the upward pressure on health care costs. By shifting the focus away from simply managing health care expenses to increasing employee ownership of total wellness, PGE is improving the balance between cost and risk

[9] "2023 Global Medical Trends Survey." Willis Towers Watson, www.wtwco.com/en-US/Insights/2022/10/2023-global-medical-trends-survey-report.

for both PGE and employees, positioning PGE to attract employees in a cost-effective manner for customers. Additionally, PGE continually benchmarks the health care benefits offered allowing for adjustments, such as a recent increase to cost sharing with employees through both premiums and increased deductibles, while still ensuring that the total benefits package remains competitive. We discuss these and other changes in more detail in Section V below.

E. Inflation

Q. Please describe the new fifth challenge – inflation.

A. Although inflation has not been a challenge within the United States for some time, that changed beginning in April of 2021. As shown on Table 2, the trailing 12-month All Urban Consumer Price Index (CPI) increased in April 2021 by nearly 40% over the previous month. This was followed by a 14-month upward trend, which culminated in a measured 12-month inflationary rate of 9.1% in June of 2022, marking the highest measured inflation in 40 years. While inflation has since decreased slightly, it still hovers around 7%.

Table 2
All Urban CPI – Trailing 12 Month Change, %[10]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2018	2.1	2.2	2.4	2.5	2.8	2.9	2.9	2.7	2.3	2.5	2.2	1.9
2019	1.6	1.5	1.9	2.0	1.8	1.6	1.8	1.7	1.7	1.8	2.1	2.3
2020	2.5	2.3	1.5	0.3	0.1	0.6	1.0	1.3	1.4	1.2	1.2	1.4
2021	1.4	1.7	2.6	4.2	5.0	5.4	5.4	5.3	5.4	6.2	6.8	7.0
2022	7.5	7.9	8.5	8.3	8.6	9.1	8.5	8.3	8.2	7.7	7.1	6.5

Q. How was inflation reflected in PGE's most recent general rate case (GRC)?

A. PGE's last GRC, Docket No. UE 394, was filed in July 2021 for a price effective date of May 9, 2022. We largely prepared the test year forecast for UE 394 during the fourth quarter of 2020 and first quarter of 2021. At that time, economic forecasts did not anticipate the high

[10] Source: Bureau of Labor Statistics, All Urban Consumer Price Index

inflationary environment that materialized beginning in the second quarter of 2021, which is now expected to persist into 2024 and potentially beyond. For example, the IHS Markit forecast used in the preparation of the 2022 GRC forecasted CPI growth in 2021 and 2022 of 2.1% in both years compared with 7.0% and 6.5%[11] now realized, respectively. Additionally, given the ongoing COVID-19 pandemic, we chose not to escalate wages and expenses any more than necessary in recognition of the economic hardships due to COVID-19. While the ramifications of inflation have been pervasive and continue to impact nearly every division of PGE's business, this testimony will speak only to how inflation affects total compensation and the correlation between inflation and wages as well as health and wellness benefits and how this particular difficulty deepens the pre-existing challenge of employee retention.

Q. How is PGE responding to inflationary pressures?

A. In today's inflationary environment it is of the utmost importance that PGE designs our total compensation package with inflation in mind, as employees with compensation packages being eroded by inflation could be much more susceptible to turnover as recent research has shown a positive correlation between inflation and workforce turnover.[12] So, with employee retention in mind, PGE has responded to inflationary pressures in 2022 by providing salary increases to employees that were higher than historic rates, simply because the market cost of labor has increased with inflation.[13] Not recognizing those cost increases would expose PGE to increases in employee turnover higher than those already being experienced. In 2022

[11] Bureau of Labor Statistics, All-Urban CPI

[12] "The Effects of the "Great Resignation" on Labor Market Slack and Inflation - Federal Reserve Bank of Chicago." Www.chicagofed.org, The Effects of the "Great Resignation" on Labor Market Slack and Inflation - Federal Reserve Bank of Chicago (chicagofed.org). Accessed 16 Dec. 2022.

[13] While PGE wage escalations in 2022 were higher than historic rates, they were largely driven by and in-line with inflation.

median PGE salaries increased at a faster rate than forecasted in UE 394 for both BU1[14] represented employees, who saw a 7% wage escalation, and non-represented employees, whose wages were escalated 6% on average. In an effort to maintain our competitive position in the labor market, which serves to support employee attraction and retention in this inflationary environment, we also plan to escalate wages in 2023 and 2024 at a rate faster than PGE has historically in part due to the current economic outlook which forecasts CPI growth of 4.2% in 2023 and 2.5% in 2024, before moderating to a stable level of approximately 2.2% in 2025 and beyond.[15] For PGE, inflation is expected to play an even larger role in the costs of health and welfare benefits in 2023 and 2024, as those industries will also be impacted by growing costs of material goods, services, and labor, and as such PGE has planned and budgeted for higher costs in this area.

[14] Business Unit 1, the larger of two PGE bargaining units comprised of approximately 90% of PGE's union represented workforce.
[15] OEA December 2022 Economic and Revenue Forecast. Table A.4.
https://www.oregon.gov/das/OEA/Documents/forecast1222.pdf

III. Total Labor Requirements

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 meet PGE's requirements of delivering safe, reliable, clean, and affordable energy to customers. This includes both regular and temporary PGE employees, along with contract employees.

A. Labor Budgeting

Q. Will you be discussing PGE's full-time equivalent employee (FTE) requirements?

A. No. Simply tracking PGE employee hours does not accurately reflect the change in PGE's labor needs and can be misleading. As such, consistent with our previous GRC, we focus on total labor dollars in this proceeding. A focus on labor dollar metrics, as opposed to FTEs, is consistent with most other elements of PGE's regulatory accounting for operating expenses. Similar to non-labor expenses, any proposed increases to customer prices related to labor dollars are subject to scrutiny of output efficiency and justification. A focus on total labor dollars is consistent with how managers view the resources they need to accomplish both limited-term projects and ongoing base-business requirements. Total labor dollars is a proper reflection of PGE's labor requirements from both a historical and projected basis.

Q. Please explain.

A. Changes to the utility business model require a more flexible mix of employees. For example, changes in software development strategies may require a change from a large group of lower-wage developers to a smaller group of highly skilled (and higher-paid) senior architects. Other areas of the business may, due to talent development needs or changing technology, require a larger number of early career employees rather than a smaller number of more highly-paid senior employees. Additionally, continually shifting and evolving project work can often require specialized skill sets on a temporary basis that are more easily filled by contract employees, who can be adjusted to fit the specific skills needed, while highly specialized work that is unique to PGE and/or the regulated utility business often requires the attraction and retention of PGE employees. Contract labor is increasingly becoming more important to our regular operations as well; as we experience greater turnover, contract labor allows us to temporarily staff positions while we seek permanent employees for hard-to-fill positions.

Looking at FTEs in isolation does not accurately reflect the overall changes to PGE's labor needs, as neither contractor hours nor overtime hours are factored into the calculation. Furthermore, just as managers must manage to a budgeted amount of dollars, PGE as a company must manage its business to a total revenue requirement. As discussed above, it is possible to have either more FTEs at a lower cost or fewer FTEs at a greater cost, depending on the changes to resource needs. As such, managers place greater focus on managing their total labor budget, including contract labor, rather than simply focusing on FTEs.

Q. How does a focus on labor dollars, rather than FTEs, improve PGE's labor budgeting?

A. By holding managers to a labor budget irrespective of FTEs, they can focus on hiring the right mix of employees and not be constrained by FTE count. Labor dollar metrics allow managers the flexibility to change their workforce composition, including skillset mixes and contractor expertise, preferences by candidates to work "gigs" and to respond to changes in technology and competitive requirements. Focusing on labor dollars also allows for improved tracking of labor resources when functional distinctions are blurred (such as the distinction between operational technology and information technology).

Q. Does a focus on labor dollars, rather than FTEs, utilize different inputs in determining market reference pay points?

A. No. As discussed below, PGE continues to use well-established industry and function-based national, regional, and local benchmarks to determine market-based pay points for PGE employees.

B. Market-Based Pay Structure

Q. Please describe how PGE determines its market-based pay structure.

A. PGE regularly compares its wages and salaries to the relevant markets. To do this, we engage in a variety of compensation survey services through third-party consulting companies who specialize in collecting and producing compensation market data. These data points are then used to benchmark the salaries of various positions and roles against similar PGE positions. PGE performs regression analyses using this data to determine the midpoint for each compensation grade within the pay structure. Pay ranges are then established around the midpoint to compensate employees equitably and competitively based on factors such as performance and experience, while also controlling costs. In general, actual salaries for each position level must fall within a specific range of PGE's pay structure as determined by these mid-points and the range around the mid-point. We do, however, sometimes find it necessary to establish direct pay above or below the median, as appropriate, based on experience, scope, and impact of the role to the organization consistent with the Oregon Pay Equity Act.

Q. What has been the recent trend for overall wages and salaries in the marketplace?

A. Oregon currently has 1.6 job openings for every unemployed Oregonian seeking employment,[16] resulting in upward pressure on wages in Oregon. According to the Oregon Office of Economic Analysis (OEA):

> "…labor demand (number of jobs that firms are looking to fill) is outstripping labor supply (number of available workers) which ultimately leads to the faster wage growth."[17]

In their December 2022 quarterly report, OEA forecasts Oregon's nominal wages and salaries will increase by 5.1% and 3.9% for 2023 and 2024, respectively.[18] With such a tight labor market predicted, it is as critical as ever that PGE continue to offer a market competitive total compensation package to recruit and retain employees.

Q. Have you performed any recent comparisons of PGE's wage structure with the market?

A. Yes. In 2022, we compared our hourly non-union and salaried non-officer positions with the national utility market. As a result, we adjusted the midpoints of our pay structures to align with the market, which increased by an overall average of 3.87%.

Q. What is PGE's 2024 test year forecast for total labor?

A. Tables 3 and 4 below summarize PGE total labor costs for 2022 and 2024 by division and by cost category respectively. Additional detail can be found in PGE Exhibit 502.

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[16] OEA December 2022 Economic and Revenue Forecast, Page 12. https://www.oregon.gov/das/OEA/Documents/forecast1222.pdf
[17] OEA December 2022 Economic and Revenue Forecast, Page 12. https://www.oregon.gov/das/OEA/Documents/forecast1222.pdf
[18] OEA December 2022 Economic and Revenue Forecast. Appendix A, Table 4. https://www.oregon.gov/das/OEA/Documents/forecast1222.pdf

Table 3
Total Aggregate Labor Costs by Division ($000)

	2022 Actuals (3)	2024 Test Year (1)
Administrative and General	$111,824	$99,939
Customer Accounts	$21,989	$25,540
Customer Service	$18,315	$20,573
Generation	$56,999	$59,217
Transmission & Distribution	$219,000	$228,779
Total Wages & Salaries (2)	**$428,128**	**$433,048**

(1)2024 amounts are net of PGE's pre-filing adjustments.
(2) Numbers may not sum due to rounding.
(3) Actuals do not include Level 3 storm outage labor.

Table 4
Total Aggregate Labor Costs by Cost Category ($000)

	2022 Actuals (3)	2024 Test Year (1)
Salaried Straight Time	$194,077	$220,274
Union Straight Time	$59,499	$72,179
Hourly Straight Time	$17,561	$21,793
Union Overtime	$24,036	$18,768
Hourly Overtime	$1,093	$1,080
Temporary PGE Labor	$2,922	$1,680
Contract Labor	$67,098	$32,767
Paid Time Off (PTO)	$46,526	$56,449
Total Wages & Salaries (2)	**$428,128**	**$433,048**

(1) 2022 & 2024 amounts are net of PGE's pre-filing adjustments.
(2) Numbers may not sum due to rounding.
(3) Actuals do not include Level 3 storm outage labor.

PGE used a rate of 4.0% to escalate non-union wages and salaries for 2023 and 2024, which falls largely in line with OEA's economic forecast of 5.1% for 2023 and 3.9% for 2024[19]. For union wages and salaries, PGE also applied a rate of 4.0% for 2023 and 2024, which is built into the most recent BU1 collective bargaining agreement (CBA). We have worked hard to drive efficiencies in our labor force across our business; as shown above, the increase in overall wages and salaries is well below the effects of inflation from the base year to test year. Details of our efforts are discussed in separate testimonies.

[19] OEA December 2022 Economic and Revenue Forecast. Appendix A, Table 4. https://www.oregon.gov/das/OEA/Documents/forecast1222.pdf

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

A. Yes. To account for vacancies and/or unfilled positions, PGE has included a $11.8 million O&M reduction to its base budget wages and salaries forecast. This amount is reflected in the above tables.

Q. Please identify the bargaining unit contracts in effect with the International Brotherhood of Electrical Workers Local No. 125 (IBEW).[20]

A. There are two collective bargaining agreements, one for each bargaining unit. The largest bargaining unit, BU1, covers all union employees at work sites other than Coyote, Port Westward, and Carty. A second bargaining unit covers employees at Coyote, Port Westward, and Carty (referred to here as "BU2").

Q. Does PGE expect there to be any significant changes to these Collective Bargaining Agreements in 2023 or 2024?

A. Yes. While BU1 has a CBA in effect until 2025, BU2 is currently negotiating an agreement. As of January 2023, no CBA with BU2 has been reached.

Q. Please briefly describe how total compensation, including wages, is determined for IBEW employees.

A. Total compensation, including wages, is the result of arm's length,[21] collective bargaining between PGE and the IBEW. Under collective bargaining, wages, other parts of total compensation, and other conditions are negotiated as a whole (i.e., changes to wages and other parts of compensation are considered alongside other contract provisions like work rules and

[20] To clarify, PGE does not directly bargain with Local No. 125 for tree trimming labor. PGE secures tree trimming labor via a third-party contractor.

[21] In an arm's length negotiation, each party is acting independently and in their own self-interest.

schedules). Thus, the bargaining agreements in their entirety reflect the negotiated outcomes that both parties' support.

IV. Incentives

Q. What is incentive pay?

A. Incentive pay is part of a market competitive total compensation package where high performing employees are rewarded with a larger total annual compensation package based on preestablished performance goals and some additional rewards for extraordinary achievement. 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.

Q. What is PGE's strategy for incentive compensation?

A. As with wages and salaries, PGE's strategy is to provide incentive pay that attracts, retains, and motivates employees. The incentive goals for all participants stem from PGE's organizational performance goals, which support our progress toward our long-term strategic goals and our commitment to core values, such as delivering exceptional customer experiences, decarbonizing our portfolio, pursuing excellence in our work, and accountability for individual performance results.

Q. How does PGE determine the structure and target percentages for incentives?

A. PGE monitors the employment market and acquires information regarding incentive compensation program design practices. Then, consistent with our total compensation program design, PGE's incentive targets are set at the 50^{th} percentile, or middle of the market. Even though it is a small percentage of PGE's total compensation, incentive pay programs are common practice in the market and are a very important feature in the overall competitive compensation package; it assists PGE in attracting and retaining well-qualified and skilled employees and encourages high-level employee performance, engagement, collaboration, and productivity by attaching a portion of our employees' total compensation to both their performance and the overall performance of the company. High-performing employees benefit the company and customers when they are working efficiently and effectively and are engaged in their work. PGE's incentive programs also align employee performance goals with shared customer and company goals that strive to keep costs low, improve customer satisfaction, and maintain PGE's financial stability.

Q. Have any of PGE's incentive programs changed?

A. Yes. PGE previously utilized two main incentive programs: Annual Cash Incentive (ACI), for executives and key non-represented employees, and Performance Incentive Compensation (PIC), for all other incentive-eligible employees including front-line managers. Going forward, PGE has decided to better align PIC-eligible employees and front-line managers with company goals by joining both incentive programs together under the ACI program.[22] The primary purpose of this consolidation is to utilize an incentive program that values both individual and company goals, giving all eligible employees the incentive to engage on operational metrics, while still requiring individual performance to benefit from the program.

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

A. Incentive pay is approximately 8.8% of PGE's 2024 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 3.6% of PGE's 2024 total

[22] It should be noted that in the provided workpapers PIC and ACI still have separate lines for budgeting purposes.

compensation. Our pre-filing adjustment removes 50% of the cost of non-officer ACI, non-officer stock, and notable incentives, and eliminates 100% of officer ACI and officer stock incentives, a reduction we make to lower our request in this rate case, while continuing to maintain that 100% of our incentive costs are prudent utility expenditures in support of safe, reliable, clean, and affordable energy for our customers. Table 5 below summarizes PGE's actual incentive costs for 2022 and our request for 2024. We discuss the three categories of incentive plans in subsections A and B below.

Table 5
Total Incentives ($000)

Incentive Plans	**2022 Actuals**	**2024 Test Year(1)**
Performance Incentive Compensation	$12,133	$0
Annual Cash Incentive	$15,384	$0
Annual Cash Incentive (combined ACI/PIC)	$0	$15,130
Subtotal ACI & PIC	**$27,516**	**$15,130**
Stock (long-term incentive plan)	$14,550	$4,803
One-time recognition and Miscellaneous	$323	$402
Total Incentives(2)	**$42,389**	**$20,336**

(1) *Amounts are net of PGE's pre-filing adjustments.*
(2) *Numbers may not sum due to rounding.*

A. Annual Cash Incentive

Q. What is the Annual Cash Incentive (ACI) plan?

A. PGE's ACI plan is the cash incentive plan for all incentive eligible employees. The plan utilizes individual performance metrics, as well as operational and strategic metrics to determine the payout.

Q. Please describe the ACI plan's operational goals and how they align key employee performance measures with customer interests.

A. PGE aligns its ACI plan with customer interests by basing the incentive payouts on PGE's success in achieving strategic, operational, and financial goals with the majority of payout designed to support customer interests as described below:

- Corporate Strategy: This goal measures the execution on PGE's long-term corporate strategies through annual key initiatives that align to the long-term strategies of: 1) Ensure resource adequacy as we decarbonize, leveraging regional partnerships and effective resource acquisition; 2) Scale solutions that deliver value through the accelerated adoption of prioritized offerings for customers that achieve their individual goals and effectively plan, forecast and connect new load and distributed energy resources; and 3) Drive operational excellence and innovation through injury management and strategic innovation.
- Customer Satisfaction: This goal measures the overall satisfaction of PGE's retail customer groups using results from market research studies conducted by Market Strategies International (MSI).
- Distribution Reliability: This goal uses annual results of the company's System Average Interruption Duration Index (SAIDI), which evaluates both frequency and duration of outages. SAIDI combines the following measures: 1) System Average Interruption Frequency Index (SAIFI), which is the number of interruptions that the average customer would experience; and 2) Customer Average Interruption Duration Index, which is the average time once the outage occurs to restore service to the customer.

- Generation Reliability: This goal utilizes a combined metric that supports the availability of the plants to operate and the minimization of unplanned thermal plant outages.
- Employee engagement: This goal uses annual results of the company's employee engagement survey to measure 1) how happy PGE employees are working at PGE and 2) if PGE employees would recommend PGE as a great place to work. This goal directly addresses PGE's need to recruit and retain well-qualified, skilled employees.
- Diversity: This goal is measured in diversity in both women and BIPOC[23] employees in two categories: 1) leadership; and 2) supply chain diversity. PGE values gender, racial, and ethnic diversity. Given that companies in the top quartile of diversity are more likely to achieve better overall performance,[24] we strive for diversity within our own ranks and with those we partner with.
- Financial Performance: This goal measures the net income target established by our Board of Directors. PGE's financial strength will reduce customer prices through lower borrowing costs and, thus, a lower overall cost of capital. Financial strength also supports PGE's access to capital to support necessary investments that benefit customers.

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[23] Black, Indigenous, and People of Color.
[24] Hunt, Dame Vivian, et al. "Why Diversity Matters |McKinsey." www.mckinsey.com, 1 Jan. 2015, "Our latest research finds that companies in the top quartile for gender or racial and ethnic diversity are more likely to have financial returns above their national industry medians."

B. Other Incentive Plans

Q. Please describe PGE's long-term stock incentive program.

A. PGE initiated its stock incentive plan in 2006 and it reflects current market practice. Many publicly traded companies (including most utilities) provide long-term incentives to promote performance and retention of directors, officers, and key employees. These awards are earned and paid out in three-year cycles.[25] The Public Utility Commission of Oregon (Commission) approved this stock issuance in Docket No. UF 4226 and summarized the goals of the plan:

> The Plan is part of the Company's overall compensation package and is intended to provide incentives to attract, retain, and motivate officers, directors, and key employees of the Company.[26]

PGE's 2024 forecast for its long-term stock incentive program is $14.9 million, but our request is approximately $4.8 million for the 2024 total long-term incentive expense. Our request reflects the removal of 100% of Officer Long-term Incentive Program costs and a 50% reduction for all other stock incentives.

Q. Does PGE have other programs that reward employees' exceptional performance?

A. Yes. Individual specific one-time recognition awards and other miscellaneous awards are given to employees on a case-by-case basis for exceptional performance beyond the annual incentive programs. These awards are distributed to recognize employees' outstanding work on a specific project or task. PGE's 2024 forecast for one-time recognition awards is approximately $0.8 million, but our request is approximately $0.4 million, reflecting a 50% reduction.

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[25] A portion of the long-term incentive program is now paid out annually in the form of restricted stock units.
[26] Commission Order No. 06-356, p.1.

At times, and in specific situations, we have also employed other types of incentives, such as signing bonuses and retention payments, to obtain difficult-to-locate talent, in periods of critical skill competition, to motivate the completion of important tasks, or to hold employees in cases of future layoffs (e.g., Boardman decommissioning). However, these types of incentives are not included in the 2024 test year.

V. Benefits

Q. What is PGE's benefit compensation strategy?

A. The health and wellbeing of PGE employees and their families is critical to serving our customers. Research supports that when employees are provided a holistic wellness package, they are able to be more productive at work.[27] PGE strives to maintain a benefits package that meets our employees' needs and balances the features and costs both among employee groups and against what other employers in our market provide to their employees. As with the other two compensation components (total labor and incentives), PGE compares our benefits programs to the relevant market attributes. PGE also uses market information to create innovative program designs to provide greater employee choice and improve our ability to control costs. As a result, we believe that our total compensation package as filed is sufficient to attract and retain well-qualified and skilled employees and is reasonable for customers.

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

A. There are four major components to PGE's 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 6 below, we project 2024 test year employee benefit costs of approximately $105 million, an increase of $18 million compared to 2022 actuals. The leading drivers of the increase are post-retirement and health and wellness benefit costs. Partially offsetting these increases are savings in group life insurance and benefits administration.

[27] PGE's third-party wellness platform provider has performed studies that show their members take 15-30% less sick time per year, have lower rates of on-the-job injury, lower costs related to Worker's Compensation claims, and lower overall health care claims costs compared to non-members.

Table 6
Total Benefits ($000)

Benefits Category	2022 Actuals	2024 Test Year
Health and Wellness	$50,641	$54,734
Disability and Life Insurance	$2,857	$3,627
Post-Retirement	$36,565	$46,321
Miscellaneous Benefits	$929	$1,478
Benefits Administration	$1,000	$608
Total Benefits*	$93,767	$106,769

** Numbers may not sum due to rounding.*

Q. Previously you discussed the expected negotiations of the collective bargaining agreement for BU2 union employees. Does PGE expect there to be any material changes to benefits in the terms of the BU2 CBA?

A. Yes. Our current expectations are that, as part of the negotiations, employees currently subject to the BU2 CBA will be offered benefits consistent with the benefits currently offered to our main bargaining unit employees.

Q. Does PGE use a benefits benchmark to measure and compare overall benefit costs?

A. Yes. PGE participates in the Willis Towers Watson Energy Services BENVAL Study, a biennial comparison of benefit values (all open health and dental, post-retirement, disability, and life insurance plans) among peer companies with similar revenues. BENVAL provides a complete competitive analysis of the value of a benefits program, including a comparison of a company's benefits plans against those of peer companies. Peer companies are those companies in similar industries with similar revenue sizes. BENVAL gathers all the relevant information related to a company's health care and other benefits plan offerings to accurately benchmark them against other peer companies. BENVAL is one of the leading benefits benchmark studies used by utilities and other large industries to evaluate the cost of their benefits plans.

Q. Please describe PGE's peer group in the BENVAL study.

A. In general terms, PGE's peer group includes 35 regulated utilities with annual revenue ranging from $1 billion to $3 billion. These peer utilities derive the majority of their revenue from their electric business. The peer group includes utilities across the U.S., with a balanced representation across the western and eastern regions.

Q. How did PGE's Health Care and Wellness costs compare to its peers in the most recent BENVAL study?

A. According to the 2021 BENVAL study, PGE's employer-paid non-union medical costs were approximately 3% above average, and 3.5% above average for total costs.

Q. How has PGE responded to the 2021 BENVAL report?

A. Beginning in 2023, PGE increased the deductibles of non-union health care benefits packages and shifted a greater share of the upfront premium costs to employees, bringing the total benefits package closer in line with the market average. These cost shifts are designed to balance the need to curtail the ever-expanding costs of health care with the need to remain attractive to current and prospective employees. With these changes, PGE expects to move even closer to average in the upcoming 2023 BENVAL report.

Q. Please explain why Health and Wellness costs are forecasted to increase approximately $7 million from 2022 to 2024.

A. There are several reasons why Health and Wellness costs are forecasted to increase, with the largest drivers being general inflation and ongoing effects of the COVID-19 pandemic. As noted earlier in our testimony, the current inflationary environment is pervasive and is expected to continue to affect health care costs. The health care industry experiences inflation like any other; the cost of materials and labor increase, and in turn health care costs must increase to cover those new higher prices. According to a recent Willis Towers Watson survey, 6.5% health care inflation can be expected in 2023, down from 9.1% and 9.4% in 2021 and 2022 respectively.[28]

Another component of the expected increases in health care costs is deferred treatment. During the COVID-19 pandemic, there was a marked decrease in health care utilization as some people chose to stay home and defer treatment, while others were unable to find health care providers for non-emergency medical care. As a result, the increase in health care costs slowed during this period. Following this phenomenon, and during a time already marked with inflation, health insurance companies now project a continued and sustained increase in health care service utilization as these patients seek treatment deferred by the pandemic[29], which is expected to drive, or at least sustain, health care inflation for the near future.

Q. What strategies is PGE employing to help slow the increase of its health care costs?

A. PGE employs several strategies to help lower the costs of health care, which historically have consistently outpaced the rate of inflation.[30] Key to all strategies employed is the alignment of the features and costs of programs with the market and a focus on employee wellness to control health care costs. The tools a company can use to affect health care costs are extremely diverse; the tools we use to execute this strategy include:

- Continual benchmarking and, if warranted, adjustments to the cost-sharing ratio of non-union medical plan offerings in order to remain in alignment with industry benchmarks;

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[28] "2023 Global Medical Trends Survey." Willis Towers Watson. 12 October, 2022.
[29] An Early Look at What Is Driving Health Costs in 2023 ACA Markets. Peterson-KFF Health System Tracker An early look at what is driving health costs in 2023 ACA markets - Peterson-KFF Health System Tracker
[30] According to Peterson-KFF "Medical care prices and overall health spending typically outpace growth in the rest of the economy" How does medical inflation compare to inflation in the rest of the economy? | KFF

- Continuing to offer consumer-driven health care plans, which consist of higher deductibles and lower premiums compared to traditional plans;
- Provision of employee wellness plans to promote healthy lifestyles and provide support to employees in their health and wellness goals.

Q. Why does PGE include wellness programs as one of its total benefits components?

A. PGE offers wellness programs to provide intervention and management of health issues, including early detection of risk factors, as well as programs to support emotional well-being and mental health. These programs promote healthier lifestyles, which contribute to lower medical premiums, increased morale, and attendance. Research supports that when employees are provided a holistic wellness package, they are more productive at work, with reduced sick time and lower rates of on-the-job injury as compared to employers who do not offer these programs.[31] Some of the services provided through these health programs include biometric testing, health risk appraisals, professional health coaching, obesity management, wellness reimbursements, and disease prevention. Also included are occupational health services, which provide flu shots, health screening, and case management.

Q. Please explain how PGE forecast its disability and life insurance benefit for 2024.

A. PGE's disability and life insurance benefits are comprised of short-term disability (STD) insurance for union employees, and long-term disability (LTD) insurance and retiree group life insurance for all employees.

[31] PGE's third-party wellness platform provider has performed studies that show their members take 15-30% less sick time per year, have lower rates of on-the-job injury, lower costs related to Worker's Compensation claims, and lower overall health care claims costs compared to non-members.

PGE forecasts STD insurance costs of approximately $0.8 million in 2024. This represents an increase of approximately $0.2 million from 2022 and is the result of actuarial fluctuations.

PGE forecasts LTD benefits for union and non-union employees to be approximately $1.7 million in 2024.[32] This represents an increase of approximately $0.9 million from 2022. PGE uses forecasts from both Willis Towers Watson and Mercer[33] to estimate these expenses. Actual LTD costs fluctuate from year-to-year, sometimes significantly. The actuarial forecasts are driven by factors such as the discount rate, health care trend assumptions, number of participants, and demographics of the participant population. The expense in a given year is calculated as the difference between beginning and ending liabilities, plus the benefits paid by PGE in that year.

PGE forecasts retiree group life insurance costs to be approximately $1.1 million in 2024. This represents a decrease of approximately $0.3 million. For union and non-union retirees, PGE pays for a basic level of coverage for life insurance. Active union and non-union members otherwise pay for their own life insurance.

Q. What is included in PGE's Post-Retirement benefits costs?

A. PGE classifies its 401(k) plan and the PGE Pension Plan as post-retirement benefits. For purposes of this testimony, we also present the Health Reimbursement Arrangement (HRA) as a post-retirement benefit.[34]

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[32] This includes approximately $0.6 million in Long-term D medical costs and $1.2 million in Long-term D income benefit projections.

[33] A global health and benefits solution company, that provides consultation services as well as brokers health care and other benefits

[34] To comply with the Employee Retirement Income Security Act (ERISA), PGE classifies the HRA as a health and wellness benefit, even though employees do not receive the benefit until after retiring from PGE.

Q. Why are post-retirement benefits important?

A. Helping employees plan for their eventual retirement through employer-sponsored post-retirement savings plans, such as PGE's 401(k) savings account, is key to PGE's attraction and retention strategy. Providing strong post-retirement benefits is a great way to enhance the total compensation package to attract and retain well-qualified, skilled employees in the current competitive marketplace.

Q. What is PGE's 401(k) forecast for 2024?

A. PGE's 401(k) costs are based on employee contributions and PGE's match, up to plan maximums, and include an employer contribution for union employees and non-union employees not eligible for PGE's legacy pension plan. These costs change with base wage and salary levels and employee participation. From 2022 to 2024, costs associated with the 401(k) are expected to increase from \$29.5 million to \$41.8 million. This trend historically has been due to a shift in employee demographics. As PGE continues to experience employee turnover, including retirements, a larger percentage of employees are not part of PGE's legacy pension plan, which ceased new enrollments in 2009 for most PGE employees. As such, they receive the employer contribution into the 401(k) plan. As this turnover continues, PGE will continue to see a smaller share of active employees in the pension plan and a larger share of active employees qualifying for the employer contribution to their 401(k) plan.

For this filing, there is an additional driver of these costs as PGE has increased this benefit in both the fixed and dollar-for-dollar match contribution levels. The newest BU1 CBA increases both the fixed contribution and the eligible match contribution by 1% of wages. Following ratification of that agreement, PGE made the decision to increase the 401k contributions for non-represented employees accordingly to support both employee attraction and retention needs of the business as well as equity across the organization.

401(k) benefit increases can have a positive effect on a company's employee attraction and retention. In fact, a 2022 survey conducted by Fidelity Brokerage Services found that respondents showed a preference for greater employer 401(k) contributions over additional PTO, company stock incentives, and full-time work from home schedules.[35] In 2022, PGE had an overall turnover rate of 10.6%; however, non-represented full-time employees at PGE had a higher turnover rate of approximately 12.5%. The turnover rate for represented employees is about half as much, coming in at approximately 6.5%. This disparity demonstrates an existing retention gap between represented and non-represented employees. Additionally, PGE does not want to create an incentive for compression, where one class of employee is unlikely to choose to grow within the organization due to the benefits of remaining in their current position. Put another way, PGE wants to avoid creating a disincentive for knowledgeable and skilled union-represented employees to pursue positions in leadership, or any other non-represented key position within the company, exacerbating the ongoing challenge of recruiting for key positions.

Q. What is PGE's HRA forecast for 2024?

A. PGE's HRA provides a post-retirement benefit to cover a portion of health care expenses and premiums for union employees who retire from PGE. Union HRA costs relate to the accumulation of notional hours for current employees and retirees receiving current HRA benefits. Total HRA costs for 2024 are expected to be approximately $2.7 million.

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[35] "Reassessing Financial Priorities After the Past Two Years of Uncertainty" Fidelity. https://s2.q4cdn.com/997146844/files/doc_news/2022/03/2-Year-Pandemic-Anniversary-Fact-Sheet_03.pdf

Q. What is PGE's pension cost forecast for 2024?

A. PGE's 2024 pension cost is forecasted to be $3.3 million (or approximately $1.7 million after capitalization), which is approximately $5.2 million less than 2022 actuals and approximately $9.1 million below the average of 2020-2022 actual pension costs. While much of this decrease in pension cost is due to an increased discount rate, some is also due to lower pension plan participation. Given that this pension plan is only available to employees hired before February 1, 2009, we expect that pension costs will continue to decrease over time. However, as we note above, decreases in pension costs resulting from decreasing participation levels are effectively offset, either in part or in full, by the increasing participation in the 401(k) plan.

Q. How is pension expense calculated?

A. Pension expense, more commonly known as "FAS 87 net periodic benefit cost,"[36] represents the cost of maintaining an employer's plan and is reported on the company's income statement. Pension expense consists of the following components: service cost, interest cost, expected return on assets, amortization of prior service cost, and amortization of net gains or losses. As part of its pension expense determination, PGE must identify an expected long-term rate of return and a discount rate.

Q. What assumption does PGE use for its expected long-term rate of return?

A. PGE's current forecast of 2024 pension expense uses an expected long-term rate of return of 6.75%, which is slightly less than the rate of 7% used in UE 394 and is based on the pension plan's asset allocation.

[36] PGE records its pension expense based on Accounting Standards Codification (ASC) 715, "Compensation – Retirement Benefits," which prior to July 1, 2009, was known as Statement of Financial Accounting Standards No. 87 or "FAS 87."

Q. What assumption does PGE use for its discount rate?

A. PGE uses a discount rate of 5.42%, which is an average of the interest rates of a group of long-term high-quality AA-rated bonds. The discount rate is provided by Willis Towers Watson, and the methodology is determined in accordance with Generally Accepted Accounting Principles.

Q. How does this discount rate compare to historical rates?

A. Discount rates have increased dramatically in the last several years. The current discount rate represents the highest discount rate used by PGE since 2011.

Q. Please discuss the current state of PGE's pension plan.

A. Overall, the funded status of PGE's pension plan has improved since UE 394 (2022 GRC), with the plan currently being 76% funded compared to 70% at the time of our last rate case.

Q. Will this result in cash contributions to PGE's pension plan?

A. Most likely, yes. Currently, we forecast contributions of approximately $26 million in 2024 and approximately $25 million in 2025 to the plan.

Q. What actions is PGE taking to de-risk the pension plan?

A. PGE has undertaken several actions to de-risk the pension plan. The first action has been a shift in asset allocation towards more fixed-income investments thereby avoiding risks associated with growth assets. In April 2021 the plan assets had approximately 35.5% allocated to fixed income, while by February 2022 PGE had increased the asset allocation to 45.0% fixed income. The second action has been a shift in administrative practices, wherein PGE removed the existing $25,000 limit on lump sum payouts upon retirement This shift allows retiring employees to exercise the financial choice they feel is best for them in retirement while allowing PGE to reduce its future plan liabilities. In 2022, lump sum payments from the pension plan totaled approximately $24 million.

Q. Please explain PGE's forecast cost for miscellaneous employee benefits.

A. Miscellaneous benefits are additional, low-cost tools that PGE uses to attract, retain, and develop well-qualified, skilled employees. We expect to spend approximately $0.89 million in 2024. Although a small percentage of PGE's overall benefits costs, these tools help balance employer provided benefits with the changing realities of our demographics and position in the marketplace for employees. Examples of PGE's miscellaneous benefits include educational assistance, service awards, and a public mass transit benefit, which is consistent with offerings from similarly situated energy and utility companies in the Northwest.

Q. What is PGE's 2024 cost for benefits administration?

A. PGE forecasts 2024 benefits administration costs to be approximately $0.6 million, which is approximately $0.4 million less than 2022 actual costs.

VI. Summary and Qualifications

Q. Please summarize your testimony.

A. Serving our customers and community is at the heart of PGE's purpose. PGE must provide a total compensation package sufficient to attract and retain the well-qualified, diverse, and skilled employees PGE needs to operate its business effectively and efficiently, and to encourage performance beneficial to PGE and our customers. To do this, PGE designs its total compensation program with reference to the labor markets in which we compete. This approach provides a total compensation structure, comprised of wages and salaries, incentives, and benefits, that as proposed will be competitive and cost-effective.

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 fourteen 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, security, and real estate services.

I'm 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 Investment Board and currently serve as the Vice Chair. I am also a member of the Partners in Diversity Leadership Council and serve on the board of Friends of the Children-Portland.

Q. Ms. Neitzke, please summarize your qualifications.

A. I received a Bachelor of Science degree in Business Administration with an emphasis in Finance from Oklahoma State University and a Post Baccalaureate degree in Accounting from Portland State University. I am a Certified Public Accountant. Prior to joining PGE in 2007, I worked at KPMG where I served in various publicly held companies as an external auditor over the course of ten years. Since joining PGE in 2007 and have held various finance-related management roles including financial reporting, treasury, corporate planning, and supply chain. I became the Director of Compensation and Benefits in early 2017.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
501	PGE Total Compensation Costs – 2020 Actuals to 2024 Test Year
502	PGE Total Labor Costs – 2020 Actuals to 2024 Test Year

Total Compensation WP	a-Dec - 2020	a-Dec - 2021	a-Dec - 2022	Dec - 2023	Dec - 2024	Base Year-Test Year Delta	Base Year-Test Year Annual %
BENEFITS							
Benefits Administration							
Benefits Administration	787,059	878,492	1,018,559	586,204	608,345	(410,214)	(22.7%)
Subtotal Benefits Administration	**787,059**	**878,492**	**1,018,559**	**586,204**	**608,345**	**(410,214)**	**(22.7%)**
Education Plan							
Education Plan	118,119	112,277	159,982	460,000	460,000	300,018	69.6%
Subtotal Education Plan	**118,119**	**112,277**	**159,982**	**460,000**	**460,000**	**300,018**	**69.6%**
Employee Assistance Program							
Employee Assistance Program	93,890	83,717	157,591	126,000	131,040	(26,551)	(8.8%)
Subtotal Employee Assistance Program	**93,890**	**83,717**	**157,591**	**126,000**	**131,040**	**(26,551)**	**(8.8%)**
Employee Wellness Program							
Employee Wellness Program	91,039	8,663	2,421	153,075	155,028	152,607	700.3%
Subtotal Employee Wellness Program	**91,039**	**8,663**	**2,421**	**153,075**	**155,028**	**152,607**	**700.3%**
Group Life Insurance							
Group Life Insurance	1,335,046	1,398,816	1,335,809	1,034,205	1,074,922	(260,887)	(10.3%)
Subtotal Group Life Insurance	**1,335,046**	**1,398,816**	**1,335,809**	**1,034,205**	**1,074,922**	**(260,887)**	**(10.3%)**
Health & Dental Plan							
Active Non-Union Health & Dental	33,199,771	31,121,225	34,376,186	34,796,400	37,878,200	3,502,014	5.0%
Active Union Health & Dental	15,327,621	15,113,486	14,887,703	14,926,700	16,400,770	1,513,067	5.0%
Health & Dental Administration	317,097	(449,417)	(766,138)	300,500	300,500	1,066,638	#NUM!
Retiree Non-Union Health & Dental	(1,207,452)	(1,001,491)	(717,627)			717,627	(100.0%)
Retiree Union Health & Dental	(17,092)	(13,126)	(13,143)			13,143	(100.0%)
Subtotal Health & Dental Plan	**47,619,945**	**44,770,676**	**47,766,982**	**50,023,600**	**54,579,470**	**6,812,488**	**6.9%**
Health Reimbursement Account							
Health Reimbursement Account	2,024,970	2,524,402	2,871,742	2,742,568	2,747,406	(124,336)	(2.2%)
Subtotal Health Reimbursement Account	**2,024,970**	**2,524,402**	**2,871,742**	**2,742,568**	**2,747,406**	**(124,336)**	**(2.2%)**
Involuntary Severance Program							
Involuntary Severance Program	3,787,475	1,649,097	1,756,858			(1,756,858)	(100.0%)
Subtotal Involuntary Severance Program	**3,787,475**	**1,649,097**	**1,756,858**			**(1,756,858)**	**(100.0%)**
Long Term Disability Benefits							
Long Term Disability Benefits	2,114,003	1,897,938	882,795	1,508,630	1,734,314	851,519	40.2%
Subtotal Long Term Disability Benefits	**2,114,003**	**1,897,938**	**882,795**	**1,508,630**	**1,734,314**	**851,519**	**40.2%**
Misc. Employee Benefits							

Total Compensation WP	a-Dec - 2020	a-Dec - 2021	a-Dec - 2022	Dec - 2023	Dec - 2024	Base Year-Test Year Delta	Base Year-Test Year Annual %
Misc. Employee Benefits	(339,761)	(389,408)	611,764	877,500	886,500	274,735	20.4%
Subtotal Misc. Employee Benefits	**(339,761)**	**(389,408)**	**611,764**	**877,500**	**886,500**	**274,735**	**20.4%**
Retirement Savings Plan							
Retirement Savings Plan	25,775,664	26,046,156	29,488,209	32,047,000	41,837,215	12,349,007	19.1%
Subtotal Retirement Savings Plan	**25,775,664**	**26,046,156**	**29,488,209**	**32,047,000**	**41,837,215**	**12,349,007**	**19.1%**
Short Term Disability Insurance							
Short Term Disability Insurance	651,090	620,110	638,260	789,400	817,800	179,540	13.2%
Subtotal Short Term Disability Insurance	**651,090**	**620,110**	**638,260**	**789,400**	**817,800**	**179,540**	**13.2%**
Subtotal BENEFITS	**84,058,540**	**79,600,936**	**86,690,971**	**90,348,182**	**105,032,039**	**18,341,068**	**10.1%**
INCENTIVES							
ACI							
Officer ACI	1,070,755	3,388,176	3,062,557	3,546,195		(3,062,557)	(100.0%)
Pelton ACI	32,785	26,930	162,696	50,092	25,933	(136,763)	(60.1%)
PGE General Operations ACI	7,920,620	10,744,025	10,843,745	11,700,879	6,057,673	(4,786,072)	(25.3%)
Wholesale Marketing ACI	964,425	1,366,155	1,314,526	1,700,740	877,540	(436,986)	(18.3%)
Subtotal ACI	**9,988,585**	**15,525,286**	**15,383,524**	**16,997,907**	**6,961,146**	**(8,422,378)**	**(32.7%)**
Notables & Misc.							
Miscellaneous Awards	1,375		24,744			(24,744)	(100.0%)
Notable Achievement Awards	131,239	183,314	297,955	778,088	402,044	104,089	16.2%
Subtotal Notables & Misc.	**132,614**	**183,314**	**322,699**	**778,088**	**402,044**	**79,345**	**11.6%**
PIC							
Biglow Canyon PIC	18,370	25,209	32,055	38,780	20,077	(11,978)	(20.9%)
Carty PIC	1,579,229	260,543	781,257	771,655	400,092	(381,165)	(28.4%)
Coyote Springs PIC	455,906	303,950	618,435	427,216	221,489	(396,946)	(40.2%)
Pelton PIC	19,624	27,315	17,353	11,907	6,164	(11,190)	(40.4%)
PGE General Operations PIC	5,659,505	13,459,929	10,067,417	13,505,264	7,030,828	(3,036,590)	(16.4%)
Port Westward PIC	831,363	925,465	595,196	921,000	477,428	(117,768)	(10.4%)
Tucannon River PIC	2,804	18,116	21,618	25,610	13,258	(8,360)	(21.7%)
Subtotal PIC	**8,566,799**	**15,020,528**	**12,133,331**	**15,701,433**	**8,169,334**	**(3,963,997)**	**(17.9%)**
Stock Incentive Plan							
Board of Directors Stock Incentives	1,185,125	1,805,916	1,397,298	1,575,000	866,250	(531,048)	(21.3%)
Officer Stock Incentives	4,441,960	6,827,164	7,544,172	5,591,385		(7,544,172)	(100.0%)
PGE Stock Incentives	5,259,792	4,972,824	5,608,337	7,130,870	3,937,129	(1,671,209)	(16.2%)

Total Compensation WP	a-Dec - 2020	a-Dec - 2021	a-Dec - 2022	Dec - 2023	Dec - 2024	Base Year-Test Year Delta	Base Year-Test Year Annual %
Subtotal Stock Incentive Plan	**10,886,877**	**13,605,904**	**14,549,807**	**14,297,255**	**4,803,378**	**(9,746,429)**	**(42.5%)**
Subtotal INCENTIVES	**29,574,875**	**44,335,033**	**42,389,362**	**47,774,682**	**20,335,903**	**(22,053,459)**	**(30.7%)**
PENSION							
Pension							
Pension	11,781,068	13,747,971	7,076,487	1,182,412	1,736,924	(5,339,563)	(50.5%)
Subtotal Pension	**11,781,068**	**13,747,971**	**7,076,487**	**1,182,412**	**1,736,924**	**(5,339,563)**	**(50.5%)**
Subtotal PENSION	**11,781,068**	**13,747,971**	**7,076,487**	**1,182,412**	**1,736,924**	**(5,339,563)**	**(50.5%)**
Total	**125,414,483**	**137,683,941**	**136,156,819**	**139,305,277**	**127,104,865**	**(9,051,954)**	**(3.4%)**

Aggregate Wages by CE w OT & Non-PGE	Dec - 2020	Dec - 2021	Dec - 2022	Dec - 2023	Dec - 2024	Base Year-Test Year Delta	Base Year-Test Year Annual %
1101: Straight-Time Labor - Salary	167,820,323	174,428,146	194,081,268	206,467,211	220,274,244	26,192,976	6.5%
1102: Straight-Time Labor - Union	56,494,788	55,175,460	59,498,739	68,748,735	72,178,684	12,679,945	10.1%
1103: Straight-Time Labor - Hourly	19,383,520	17,560,545	17,630,450	20,877,120	21,792,952	4,162,502	11.2%
1200: Other Union Labor				4,145,286	4,311,097	4,311,097	#DIV/0!
1201: Union High Time	65,817	50,474	68,274	500	500	(67,774)	(91.4%)
1202: Union Premium Pay	4,363,907	5,892,532	4,779,644	97,000	97,000	(4,682,644)	(85.8%)
1401: Overtime - Hourly	803,528	1,763,933	1,092,776	1,038,442	1,080,353	(12,423)	(0.6%)
1402: Overtime - Union	20,976,591	26,974,850	24,035,846	18,045,876	18,767,711	(5,268,135)	(11.6%)
1501: Temporary Labor Straight Time	1,917,264	2,766,980	2,922,082	1,614,459	1,680,175	(1,241,907)	(24.2%)
1502: Non-PGE Labor Straight Time	34,327,974	48,584,719	67,098,268	32,809,703	32,766,716	(34,331,552)	(30.1%)
1601: Temporary Labor Overtime	30,107	147,164	79,421	2,194	2,287	(77,135)	(83.0%)
1602: Non-PGE Labor Overtime	6,696,303	46,090,845	10,875,429	4,272,130	4,159,579	(6,715,850)	(38.2%)
5104: Vacation Overhead	41,745,064	44,109,142	46,526,928	51,045,196	56,448,199	9,921,272	10.1%
5501: Labor Allocation - ST Salary	(825,820)	(532,247)	(602,395)	(615,439)	(646,688)	(44,294)	3.6%
5502: Labor Allocation-ST Hrly Union	274,089	142,441	76,976	155,589	161,708	84,732	44.9%
5503: Labor Allocation-ST Hrly NonUn	43,550	44,487	(21,086)	(15,594)	(16,164)	4,922	(12.4%)
5505: Labor Allocation-Union Premium	(168)	(989)	(72)			72	(100.0%)
5506: Labor Allocation - Hourly OT	(10)	(40)					#DIV/0!
5507: Labor Allocation-Union HrlyOT	(2,035)	(13,880)	(4,357)	(300)	(313)	4,044	(73.2%)
5509: Labor Allocation-ST Temporary	(9,306)	(7,442)	(5,859)	(9,688)	(10,023)	(4,164)	30.8%
Total	**354,105,486**	**423,177,119**	**428,132,333**	**408,678,419**	**433,048,019**	**4,915,686**	0.6%

Aggregate Wages by Division	Dec - 2020	Dec - 2021	Dec - 2022	Dec - 2023	Dec - 2024	Base Year-Test Year Delta	Base Year-Test Year Annual %
A: Customer Accounts	22,788,196	22,158,131	21,989,129	24,340,101	25,539,900	3,550,770	7.77%
B: Customer Service	12,044,485	14,145,146	18,315,020	18,979,600	20,573,041	2,258,021	5.99%
C: A&G	89,276,255	99,387,878	111,824,376	94,692,016	98,939,071	(12,885,306)	(5.94%)
E: T&D	180,462,361	235,890,403	218,999,986	215,353,109	228,778,943	9,778,957	2.21%
G: Generating - Other	32,854,054	33,875,483	36,957,538	35,453,503	38,429,070	1,471,532	1.97%
H: Generating - Biglow	699,715	633,067	674,876	809,622	847,320	172,444	12.05%
I: Generating - Tucannon	575,528	577,366	614,873	640,409	669,714	54,841	4.36%
O: Generating - Boardman	314,894	344,128	263,517	43,098	45,131	(218,386)	(58.62%)
T: Generating - Trojan	1,485,311	1,804,677	2,542,892	2,520,434	2,637,024	94,132	1.83%

Aggregate Wages by CE w OT & Non-PGE	Dec - 2020	Dec - 2021	Dec - 2022	Dec - 2023	Dec - 2024	Base Year-Test Year Delta	Base Year-Test Year Annual %
V: Generating - Beaver	5,127,451	4,941,500	5,634,889	5,234,184	5,479,337	(155,552)	(1.39%)
W: Generating - Port Westward	3,693,407	4,079,154	4,548,881	4,518,443	4,729,983	181,102	1.97%
Y: Generating - Coyote	1,850,278	1,970,435	2,401,415	2,340,757	2,451,242	49,826	1.03%
Z: Generating - Carty	2,933,550	3,369,751	3,364,940	3,753,143	3,928,244	563,304	8.05%
Total	**354,105,486**	**423,177,119**	**428,132,333**	**408,678,419**	**433,048,019**	**4,915,686**	0

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Corporate Support

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Jim Ajello
Greg Batzler

February 15, 2023

Table of Contents

I. Introduction

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

A. My name is Jim Ajello. I am the Senior Vice President, Chief Financial Officer (CFO), and Treasurer 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 $209.9 million in administrative and general (A&G) costs in 2024, a decrease of $3.5 million compared to 2022 actuals of $213.4 million.[1]

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 to deliver safe, reliable, clean, and affordable energy to customers, including 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 601 provides a list of A&G functions plus a summary of costs for 2022 (actuals) through 2024 (test year forecast). Table 1 below summarizes major A&G costs for 2022 actuals and the 2024 test year by functional area.

[1] Unless specifically indicated as capital costs, all costs in this testimony refer to O&M costs.
[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	**2022 Actuals**	**2024 Forecast**	**Delta***
Accounting/Finance	$ 14.0	15.4	$1.4
Business Support Services	1.4	1.7	0.3
Corp Communications/Public Affairs	2.4	2.8	0.5
Corporate Governance	8.3	6.1	(2.2)
Corporate R&D	2.6	3.3	0.8
Environmental Services	2.2	2.4	0.2
Facilities/Rent	4.4	4.5	0.1
Governmental Affairs	1.8	2.2	0.4
HR/Employee Support (net of capital allocs.)	12.2	11.9	(0.3)
Hydro Licensing and Support	0.0	0.0	0.0
Insurance	17.5	21.7	4.2
IT: Direct & Allocated	17.3	17.2	(0.2)
Legal	8.7	9.2	0.5
Performance Management	0.3	0.4	0.1
Regulation	2.6	3.1	0.6
Physical Security and Business Continuity	3.4	4.8	1.4
Supply Chain/Contract Services/Purchasing	3.6	3.0	(0.6)
Sustainability and Resource Planning	0.4	0.5	0.1
Total for Major Functional Areas*	**$ 103.1**	**$ 110.4**	**$ 7.3**
Benefits (net of capital allocs.)	$ 40.0	$ 56.2	$ 16.2
Corporate Allocations (net)	(2.2)	(5.6)	(3.4)
Corporate Cost Reductions	0.0	(3.4)	(3.4)
General Plant Maintenance	4.4	3.7	(0.7)
Incentives	42.4	20.4	(22.0)
LC Fees, Revolver Fees, Margin Net Int., & Broker fees	3.2	2.9	(0.3)
Membership Expense	2.6	2.9	0.3
Regulatory Fees	10.7	15.0	4.2
Severance	1.8	0.0	(1.8)
Total Labor Loadings to A&G	0.0	0.0	0.0
Total PTO to A&G	7.5	7.5	0.0
Total Other A&G Costs*	**$ 110.3**	**$ 99.5**	**$ (10.8)**
Total A&G*	**$ 213.4**	**$ 209.9**	**$ (3.5)**

**May not sum due to rounding.*

Q. How would you characterize the forecasted change in A&G costs from 2022 to 2024?

A. While total A&G costs decrease overall when comparing 2022 actuals to the 2024 forecast, there are specific cost increases attributed to three primary drivers: insurance, benefits, and physical security/emergency management. Insurance costs continue to be subject to the same trends that we identified in PGE's 2022 general rate case (UE 394) and describe in more detail below. Benefits, as discussed in PGE Exhibit 500, are largely driven by health care and retirement costs. Physical security and emergency management costs are driven by additional security support needs and the growing recognition of the potential for detrimental events (e.g., wildfires, storms, substation security, etc.) and the need to protect critical energy infrastructure. While we can and do actively manage costs associated with these drivers, they are primarily external to PGE and reflect larger market conditions and/or regulatory requirements beyond our control. Additionally, we are forecasting a modest increase in IT costs, as these systems continue to be integral to all aspects of PGE's operations.

Q. Is PGE facing any other challenges in managing cost increases?

A. Yes. A major challenge PGE is facing throughout the business is increasing inflationary pressures, which are impacting current costs and are projected to impact future budgets beyond forecasted escalations PGE has included within this case. The trailing 12-month All Urban Consumer Price Index (CPI) increased in April 2021 by nearly 40% over the previous month. This was followed by a 14-month upward trend, which culminated in a measured 12-month inflationary rate of 9.1% in June of 2022, marking the highest measured inflation in 40 years.[3] More recently, according to the December 2022 Bureau of Labor Statistics Consumer Price Index News Release, "Over the last 12 months, the all items index increased

[3] *See* PGE Exhibit 500, Section II, E. "Inflation" for further detail.

6.5 percent."[4] Given this information, inflation could result in future impacts to our 2023 and 2024 budgets as we move through the year. Despite the highest inflation seen in approximately 40 years and excluding the increases for insurance, benefits, physical security/emergency management, and Public Utility Commission of Oregon (OPUC or Commission) fees (which are a revenue-sensitive cost included in A&G), PGE's A&G costs decrease by approximately $29.6 million from 2022 to 2024.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II: Primary A&G Cost Increases
- Section III: Information Technology
- Section IV: Summary
- Section V: Qualifications

[4] Press Release, United States Department of Labor, Bureau of Labor Statistics, USDL-23-0017 at page 1, released January 12, 2023, available at: https://www.bls.gov/news.release/pdf/cpi.pdf

II. Primary A&G Cost Increases

A. Insurance

Q. What types of insurance coverage does PGE maintain?

A. PGE maintains a prudent portfolio of insurance coverage consistent with industry peers, which we list and describe in PGE Exhibit 602 and confidential PGE Exhibit 603. In addition to using insurance to manage its risks, PGE is also looking at alternative risk financing mechanisms (e.g., captive insurer) as a means of reducing its overall cost of risk. In general, the insurance coverage maintained by PGE falls into two broad programs: Property and Casualty. We discuss these, as well as retained losses, below.

Q. What is PGE's forecast for insurance premiums for 2024?

A. As shown in Table 2 below, we expect total Property and Casualty premiums to be approximately $28.4 million. This compares to actual 2022 costs of $20.2 million, an annualized increase of 18.5%.

Table 2
Insurance Premiums ($ millions)

Type of Loss	2022 Actuals**	2023 Budget**	2024 Forecast**	Annualized % Increase
Property	$10.2	$12.3	$16.6	27.6%
Casualty	$10.0	$11.3	$11.8***	8.6%
Totals*	**$20.2**	**$23.6**	**$28.4**	**18.5%**

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

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:

- Main All-Risk Property;
- Renewables All-Risk Property;

- Fidelity & Crime; and
- Sabotage & Terrorism.

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

A. PGE expects its renewables and traditional Property insurance premiums to increase at a 27.6% annualized rate. In the Property insurance market, utility insurers continue to struggle to make an underwriting profit. 2022 is the second consecutive year in which the estimated insurance industry losses total more than $100 billion.[5] As a result of these challenges, insurance carriers are requiring double-digit rate increases while pushing for increased deductibles or reducing available limits to manage their portfolios. This environment is largely driven by inflation, supply chain constraints, insured losses (e.g., wildfires, floods, tornadoes, hail, etc.), and a challenging reinsurance environment.

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);

[5] *See* Wells, Kane. *Global Insured Losses in 2022 Likely to be About $100bn, Says KBW*, REINSURANCE NEWS (October 10, 2022), available at: https://www.reinsurancene.ws/global-insured-losses-in-2022-likely-to-be-above-100bn-says-kbw/

- Sabotage & Terrorism; and
- Surety Bonds.

PGE Exhibit 602 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 14.7% in its General Liability insurance program. The adverse impacts of wildfire losses in California over the last decade continue to be a primary driver of this large premium increase. Additionally, the 2020 Labor Day fires in the Pacific Northwest, along with subsequent fires in 2020 and 2021[6] continue to shed light on the catastrophic exposure faced by utilities in the region. Other exposures that continue to increase underwriting scrutiny and adversely impact utility insurance pricing in the U.S. and Bermuda markets are the perceived risk of large auto fleets, gas pipeline infrastructure, use of drones, hydro facilities, and their safety protocols, and "nuclear verdicts" (i.e., liability claims greater than $10.0 million).

Workers' Compensation insurance is expected to see rate increases in the 5% to 10% range and remains subject to increasing pressure due to industry-wide losses combined with a general rise in medical costs, wage growth, an aging workforce, and the transition back to an in-person work environment – all of which are putting pressure on Workers' Compensation rate adequacy in 2023 and 2024. Cyber Liability rate increases accelerated throughout 2022, with average increases for all accounts up 20%. 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

[6] Beachie Creek, Archie Creek, Holiday Farm, and Slater fires in 2020, Bootleg fire in 2021 and Cedar Creek fire in 2022.

anticipate an 18.5% average annualized impact on premiums without taking into account any unknown increases in premiums due to the natural disaster consequences discussed above between 2022 and 2024.

Q. Why is D&O insurance coverage important?

A. D&O liability insurance is important for the following reasons:

- Maintaining the appropriate limit and type of D&O insurance is necessary to attract and retain qualified and competent directors and officers;
- It shields PGE's directors and officers against normal, but sometimes significant, risks associated with managing the business; and
- It insulates customers and shareholders from having to bear the full financial impact in situations where PGE owes its directors and officers an indemnity obligation, or where PGE is a named party in securities litigation.

Q. Has PGE included 100% of D&O insurance coverage in the 2024 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. It should also be noted that any increases to PGE's D&O insurance coverage are not driven by the 2020 trading event and are instead reflective of general D&O market conditions.

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 2022 to 2024?

A. As shown in Table 3 below, PGE expects annual retained losses for Workers' Compensation and Auto and General Liability claims to increase by an annual average of 21.6% from 2022 to 2024. In 2023 and 2024, 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	2022 Actuals	2023 Budget	2024 Forecast	Annualized % Increase
Auto & General Liability	$1.7	$2.6	$2.6	24.6%
Workers' Compensation	$1.4	$1.9	$1.9	17.7%
Totals*	**$3.0**	**$4.4**	**$4.5**	**21.6%**

**May not sum due to rounding*

Q. Why does PGE purchase Workers' Compensation insurance?

A. The State of Oregon requires PGE to maintain coverage to provide employees who are injured on the job with insurance coverage that will compensate them for lost wages, medical care, and if necessary, vocational rehabilitation.

B. Benefits

Q. Please describe PGE's employee benefits package.

A. PGE strives to maintain an employee benefits package that meets our employees' needs and balances the features and costs among employee groups against what other employers in our market provide. There are four major components to our benefits package: 1) health and wellness; 2) disability and life insurance; 3) post-retirement; and 4) miscellaneous benefits.

Q. How much do you expect benefits costs to increase from 2022 to 2024?

A. The estimated increase in net benefit costs from 2022 to 2024 is approximately $13.0 million and includes such items as health and dental plans, 401(k) plans, pension costs, and employee life and disability insurance.

Q. What accounts for this increase?

A. The primary drivers are increasing premiums for health care and dental insurance coupled with increasing retirement savings plan costs. PGE Exhibit 500 explains in greater detail how the compensation and benefits-related costs are affected by these increases and how PGE remains competitive in a labor market for specialized and qualified applicants who can help deliver the high service quality levels our customers expect. Please note that the benefit amounts in Table 1 represent the “net” changes within A&G only, as compared to the gross costs applicable to corporate PGE. Net A&G refers to the amount remaining in A&G <u>after</u> labor loadings apply certain amounts of these costs to capital projects and “below-the-line” activities. PGE Exhibit 500 explains the gross corporate forecast for these costs.

Q. How does PGE mitigate cost increases for employee benefits?

A. As discussed in PGE Exhibit 500, PGE works to keep benefit costs down by sponsoring programs that encourage a healthy workforce, modifying benefits plan structures to track market practice, and discontinuing certain programs when it makes sense. Our goal is to maintain a fair and competitive benefits package that will help us attract and retain a quality workforce, while still controlling costs.

C. Physical Security and Emergency Management

Q. How much do you expect Physical Security and Business Continuity and Emergency Management (BCEM) costs to increase from 2022 to 2024?

A. As shown in Table 4 below, Physical Security costs are forecasted to increase from approximately $2.5 million in 2022 to $3.7 million in 2024. BCEM costs are expected to increase from approximately $0.9 million to $1.1 million over the same period.

Table 4
Security and Emergency Management Costs ($ millions)

Functional Area	2022 Actuals	2023 Budget	2024 Forecast	Annualized % Increase
Physical Security	$2.5	$3.1	$3.7	21.7%
BCEM	$0.9	$1.1	$1.1	13.2%
Totals*	**$3.4**	**$4.2**	**$4.8**	**19.6%**

**May not sum due to rounding*

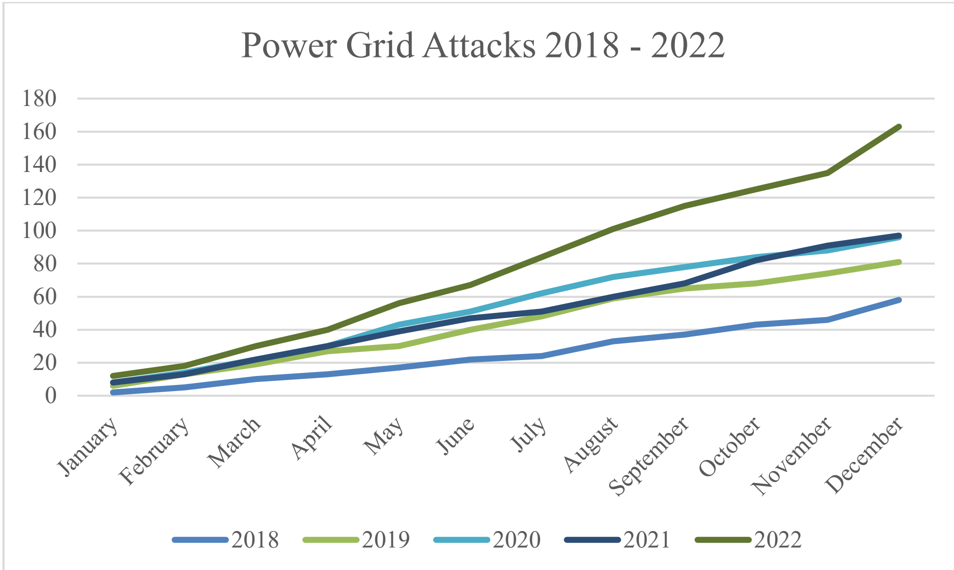
1. Physical Security

Q. Have electric utilities recently been exposed to attacks that were detrimental to critical energy infrastructure?

A. Yes. Since at least 2018, the number of incidents reported by utilities to the U.S. Department of Energy that were deemed to be intentional attacks, threats of an attack, or vandalism on a utility's system has been increasing year-over-year.[7] Figure 1 below summarizes these power grid attacks.

[7] *See* Electric Disturbance Events Annual Summaries, available at: https://www.oe.netl.doe.gov/OE417_annual_summary.aspx

Figure 1
Cumulative number of reported attacks on U.S. power grid infrastructure



More recently, in December 2022, transformers at two different Duke Energy (North Carolina) substations were shot, resulting in over 45,000 customers losing power. Just days later, another Duke Energy asset – its Wateree Hydro Station (South Carolina) – was also shot, although this incident did not result in any power disruptions.[8] At a more regional level, since June 2022, there have been at least 14 known incidents of sabotage targeting substations in Oregon and Washington, one of which was PGE's Town Center Substation. Other examples include six substations in the Pacific Northwest damaged by attacks in November 2022 and over 14,000 Washington customers that lost power in December 2022 after two Tacoma Power and two Puget Sound Energy substations were attacked with the intent to disrupt power to commit a burglary. The damage to the Tacoma Power substations alone is estimated to be at least $3 million.[9]

[8] Walton, Robert. *FBI Called to Investigate Firearms Attacks on Duke Energy Substations in North Carolina; 40K Without Power*, UTILITYDIVE (December 4, 2022), available at: https://www.utilitydive.com/news/fbi-investigate-firearms-attacks-duke-energy-substations-North-Carolina/637927/
[9] United States Attorney's Office, Western District of Washington (2023, January 3), *Two Charged With Attacks on Four Pierce County Power Substations*, available at: https://www.justice.gov/usao-wdwa/pr/two-charged-attacks-four-pierce-county-power-substations

These, and other recent attacks have underscored the need for PGE and other utilities to reinforce security capabilities to protect utility assets and customers. PGE is very focused and engaged in addressing any threats to our electric system reliability and strengthening (as needed) our security capabilities to keep our systems and customers safe.

Q. Please describe the structure of PGE's Enterprise Security function.

A. The Department of Homeland Security (DHS) Cybersecurity and Infrastructure Security Agency has recognized Security Convergence – the combining of Cyber and Physical Security into an Enterprise Security model – as an industry best practice. In October of 2021, PGE reorganized its Cyber and Physical Security functions into one Enterprise Security model under one director. This converged Enterprise Security model recognizes that threats to utilities are rarely cyber or physical in nature alone (e.g., physical access to a site can facilitate a cyber intrusion or vice-versa). By operating under a single Enterprise Security model, PGE's Cyber and Physical Security organizations will be better able to collaborate and complement one another to better secure our systems and keep our customers safe. We discuss PGE's Physical Security team below. For detail on enhancements to PGE's Cybersecurity team and capabilities, see Section III, C and Exhibit 610.

Q. What are the duties of PGE's Physical Security team?

A. PGE's Physical Security team is tasked with providing and maintaining security for our employees, assets, and customers at all our sites throughout our service territory, including those where employees work, where electricity is generated, or where our transmission lines travel. The type and extent of security measures used at different locations are dependent upon many things, including importance to the electrical grid, customer impact, employee impact, assets enclosed within or on the site, and regulatory requirements such as North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards.[10]

PGE's Physical Security team is also tasked with upgrading the security of our physical assets, such as substations, so that we will be able to detect potential intrusions earlier and appropriately respond as quickly as possible. To adequately upgrade our substations and other physical assets, in 2022, PGE's Enterprise Security team developed and implemented a risk-based tiering approach for all 561 physical PGE assets – approximately 175 of which are substations – that we expect to be complete by the end of 2023. Using this risk-based tiering process, PGE is developing a multi-year plan to continue the security capabilities of our substations and other physical assets based on where they fall within the priority tiering model. This will be an aggressive multi-year schedule, but it is necessary to protect and maintain the security of our substation sites to provide a reliable and resilient system for our customers.

Q. Why is it important for PGE to improve the security of its sites?

A. The importance of maintaining and improving the security at our sites is becoming increasingly apparent as attacks on critical energy infrastructure, as previously mentioned, become more pervasive. For example, it can only take a few minutes for perpetrators to enter a substation and cause millions of dollars of damage that also results in service interruptions for our customers.

Q. Please describe the reasons for increasing physical security costs.

A. When comparing 2022 actuals with our 2024 forecast, the increase in physical security costs is driven by overall inflationary pressures, additional labor needs to strengthen the capacities and capabilities of PGE's Physical Security team, and lower-than-expected Integrated

[10] NERC CIP standards are the mandatory security standards that apply to entities that own or manage facilities that are part of the U.S. and Canadian electric power grid.

Operations Center (IOC) physical security costs in 2022. The reason behind the latter is PGE's third-party security services provider was unable to completely fill all staffing positions throughout 2022, however, the IOC remained secure during this time.[11]

Q. Why was PGE's security services provider unable to fill all vacant security positions in 2022?

A. PGE's security services provider, Allied Universal (Allied), experienced challenges to fill all vacant security officer positions in 2022 for a variety of reasons that have more broadly impacted current labor force participation. These include, but are not limited to, cumulative effects from the COVID-19 pandemic resulting in lower workforce participation due to increased unemployment benefits, stimulus checks, and expanded work from home opportunities. These factors created a unique environment where it was difficult to fully staff PGE's IOC security team. However, as of December 2022, PGE's IOC security team is fully staffed, and we expect this to be the case into 2023 and 2024.

Q. Why does PGE's Physical Security team require additional support?

A. Over the past several years, PGE's Physical Security team has been actively adding security protocols and equipment to protect assets and employees, thus providing a safer work environment and a more stable power grid – all without any additions to PGE's Physical Security team personnel. During this time, the city of Portland and surrounding areas have observed a substantial increase in crime.[12] Responsibilities of PGE's Physical Security team include, but are not limited to, assisting with threats and transient/homeless issues, hazardous

[11] The IOC remained secure during this time because Allied covered and paid for necessary overtime shifts. The IOC became fully staffed in December 2022.
[12] The number of Portland criminal offenses has increased from 60,665 in 2020 and 65,558 in 2021 to 71,430 in 2022, as shown in data provided on the City of Portland Police Bureau's website, available at: https://www.portlandoregon.gov/police/71978

material clean up, addressing issues (in collaboration with law enforcement) such as burglary, theft, criminal mischief, abandoned vehicles, non-criminal investigations, annual security inspection of all 561 physical PGE assets, etc. Threat assists can be a broad category, and this work requires researching past threats and planning with field operations to execute the mission(s) in the safest manner possible. Some calls for assistance require the assignment of multiple PGE security personnel for safety purposes, in addition to time spent on follow-up and collaboration with law enforcement. With these day-to-day responsibilities, additional physical security labor is also needed for the design, planning, and execution of risk-based tiering of 561 physical PGE assets, as previously described. Additional labor will also allow for 24/7 Integrated Security Operations Center (ISOC) asset monitoring at a higher level than Allied is currently providing, as well as the development of ISOC threat intelligence capability.[13]

In summary, the demands of PGE's Physical Security team have been outpaced by current staffing levels and the additional support will enable the team to continue to augment the critical security measures we are installing and provide the service, support, and security that all PGE employees and customers expect.

2. Business Continuity and Emergency Management – BCEM

Q. What is the history and purpose of the BCEM department?

A. As an essential service provider for our customers and the region, it is critical that PGE is prepared for incidents that can interrupt business processes; our customers, investors, regulators, partner utilities, and other stakeholders expect nothing less. PGE established the BCEM department in 2007 to strengthen capacities and capabilities for the preparation,

[13] The ISOC is a group that sits within the IOC that monitors our physical and cybersecurity systems.

mitigation, and response to significant emergency incidents that may adversely affect service to customers, company assets, and employees. This includes providing planning, training, and support for exercises (e.g., grid exercises, wildfire exercises executing the Public Safety Power Shutoff (PSPS) Plan, annual Corporate Incident Management Team (CIMT) outage drill, etc.) to recover critical functions as quickly as possible and in compliance with all regulatory requirements. In short, PGE's BCEM department 1) establishes business continuity and emergency management plans and procedures; 2) conducts risk and business impact assessments; 3) develops training programs and materials; and 4) establishes and operates emergency operations center functions and facilities needed to effectively prepare for, respond to, and recover from, a variety of emergency incidents.

Q. Please describe the reasons for increasing BCEM costs.

A. It is critical that PGE be prepared for incidents that can interrupt business processes. To consistently meet this requirement within a constantly changing environment, PGE must continue to evolve its BCEM programs to strengthen its capabilities and enhance its resilience.

When comparing 2022 actuals with our 2024 forecast, the increase in BCEM costs is the result of three drivers. First, PGE intends to expand training and exercises for PGE's CIMT to increase reliability and effectiveness when responding to outage events. These trainings and exercises are critical to PGE's operations, especially considering that from 2020 – 2022 PGE's CIMT was activated 12 different times for a combined duration of 57 days.[14] Second, increased BCEM department assistance via plans and exercises (e.g., business continuity plans, disaster logistic plans, enterprise outage plans, employee assistance program exercises, etc.) will provide enterprise resilience and increase reliability by ensuring that PGE

[14] This does not include a 2020 COVID-related activation that lasted 282 days.

will have the ability to recover from any event that affects employee availability to report to work. Finally, the costs for these essential pieces of training themselves have increased due to inflationary pressures. For example, the cost of the CIMT training and exercise consultants has increased by approximately 15% from 2022 to 2024.

While the increase in BCEM costs is relatively small, it is necessary so that the department can continue its work on the activities PGE needs to perform to strengthen its regional preparedness and resilience capabilities among its primary facilities and systems.

III. Information Technology

A. Accounting Treatment of IT Solutions

Q. Briefly summarize the two types of IT solutions available to PGE.

A. There are two IT solutions available to PGE: cloud-based and on-premise. The primary difference between the two is where the solution itself is housed: on-premise solutions are utility-owned assets and are installed locally on PGE's computers and servers, whereas cloud-based solutions are hosted on a vendor's server and accessed remotely. These vendors host cloud-based solutions as their core business model, whereas PGE utilizes cloud-based solutions to support our core business model of delivering safe, reliable, clean, and affordable energy to customers. Given the numerous advantages (e.g., security, scalability, reliability) of cloud-based solutions compared to traditional on-premise solutions, cloud-based solutions continue to replace on-premise solutions.

Q. Why are cost-effective cloud-based solutions the better option for PGE and its customers?

A. Cloud-based solutions can often strengthen our cybersecurity capabilities and be deployed faster, more economically, and more effectively than the traditional on-premise solutions that they are replacing. Cloud-based solutions provide improved scalability (for high-demand events), efficiency, agility, and security for its user, and can be more regularly updated and upgraded by the owner/operator (e.g., Google, Oracle, IBM, etc.), minimizing business disruptions for PGE and our customers and reducing the risk of obsolescence. Costs associated with updating, fixing, and/or replacing hardware and/or software are generally lower for cloud-based solutions as a vendor can often complete a single software upgrade installation into the cloud for thousands of its customers. Cloud-based solutions are location and device independent which increases natural disaster resiliency during events such as wildfires, ice storms, earthquakes, etc. Cloud-based solutions are also more energy efficient than traditional on-premise solutions and free up resources (that would typically focus on operating and maintaining traditional on-premise solutions) to other areas of PGE's operations to better serve our customers and focus on our core business. Exhibit 605 provides greater detail on some of the benefits of cloud-based solutions specific to PGE and our customers.

Q. From an accounting perspective, how are on-premise and cloud-based IT solutions treated?

A. Because cloud-based solutions offer numerous advantages over on-premise solutions, they continue to replace traditional on-premise solutions. Unfortunately, accounting guidelines have not kept pace with this rapidly changing technology environment. For example, PGE currently capitalizes on-premise IT solutions because they are installed locally. In contrast, cloud-based IT solutions are considered an O&M expense because they are hosted on the vendor's server.

Q. What is the consequence of this disparate accounting treatment?

A. Because accounting guidelines have failed to keep pace with this changing technology environment, there is an inherent disincentive for utilities to invest in superior cloud-based solutions. The National Association of Regulatory Utility Commissioners (NARUC), which is an organization whose mission is to serve the public interest by improving the quality and effectiveness of public utility regulation, has specifically addressed this issue, noting:

> The disparity in accounting treatments between these two software approaches creates a regulatory incentive for utilities to invest in on-premise software solutions and creates unintended financial hurdles that hinder utilities from realizing the benefits that so many other industries are experiencing with cloud-based software. Utilities should be free to make software investments based on which option best meets both the needs of the utility and its customers, rather than how the investment

> will be treated for accounting purposes. The existing regulatory accounting rules may be interpreted, if appropriate, to allow for utilities to capitalize cloud-based software.[15]

Overall, the IT solutions landscape has shifted away from a capital investment model to an O&M model, and the asymmetry in accounting treatment has created unnecessary complexity and an imbalance of incentives for PGE when considering which IT solutions (on-premise or cloud-based) are best for our business and our customers.

Q. Have any other utility industry organizations or associations addressed this issue?

A. Yes. The gap in accounting treatment that creates an inherent financial disincentive for PGE and other utilities to invest in modernized cloud-based solutions is a nationally recognized issue. Organizations such as NARUC (as previously mentioned), Edison Electric Institute (EEI), and Information Services Group (ISG) have advocated for utilities to not only invest in cloud-based solutions, but for regulators to allow O&M expenses, such as license fees, associated with these cloud-based solutions to be rate based. For further detail, please see Exhibit 604.

Q. How does PGE propose to address this issue?

A. To address this issue and account for the shift in where IT solutions are being hosted (i.e., on-premise to cloud-based), PGE proposes to include the unamortized balance of applicable license and hosting fees associated with prepaid cloud-based solutions with a contract length of three years or greater as a regulatory asset in rate base. The current forecast of this amount as of December 31, 2023 totals approximately $8.2 million.

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[15] *See* NARUC November 16, 2016 "Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements," available at: https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476

Q. Please describe the various cost components of cloud-based solutions and their current accounting treatment.

A. Cloud-based solutions consist of four primary cost components: implementation costs, license fees, hosting fees, and maintenance/support costs. These are defined in detail below:

- Implementation Costs - Costs incurred to complete the necessary steps to use a solution. Accounting guidelines (i.e., Financial Accounting Standards Board (FASB) and Generally Accepted Accounting Principles (GAAP))[16] allow PGE to capitalize these costs for both on-premise and cloud-based solutions, which PGE currently does.
- License Fees - Costs incurred to use and have access to the solution itself. Current accounting guidelines allow PGE to capitalize these costs for on-premise solutions and some, but not all, cloud-based solutions.
- Hosting Fees - Costs paid to the vendor for hosting the solution(s) on the vendor's own computing and storage resources. Under current accounting guidelines for cloud-based solutions, these costs are separated from the software license and are not capitalized as utility plant.
- Maintenance/Support - Costs for general corrective maintenance and/or troubleshooting. Current accounting guidelines do not allow PGE to capitalize these costs for either on-premise or cloud-based solutions. PGE is not proposing to capitalize these costs.

Under PGE's proposal and consistent with on-premise solutions, in addition to implementation costs, PGE would include in rate base, the license fees and hosting fees for prepaid cloud-based solutions with agreements at least three years in length. Doing so

[16] Accounting Standards Update (ASU) 2018-15 and Accounting Standards Codification (ASC) 350-40.

effectively "levels the playing field" when considering which IT solution (on-premise or cloud-based) is best for PGE and our customers.

Q. How does PGE's proposal "level the playing field?"

A. Cloud-based solutions are replacing on-premise solutions that typically have an amortization period of three to ten years. Fundamentally, the only difference in how PGE can currently record these costs is where the solution is hosted. With the accounting treatment being equal, regardless of IT solution option, the selection criteria become focused more squarely on selecting the least cost, least risk solution.

Q. Can PGE already capitalize license fees for some cloud-based solutions?

A. Yes. Accounting guidelines[17] allow the capitalization of license fees associated with cloud-based solutions if the following criteria are met:

a) PGE has the contractual right to take possession of the software at any time without significant penalty;[18] and

b) PGE can run the software on its own on-premise hardware or contract with another party unrelated to the vendor to host the software.

PGE aims to satisfy these criteria during contract negotiations with software vendors so that we can capitalize license fees. However, these criteria are not always attainable, and PGE anticipates it will not be able to meet these criteria for many future cloud-based solutions.

Q. Is there a cost benefit to these prepaid contracts?

A. Yes. In fact, even when factoring in PGE's return requirements, the savings achieved by pre-paying upfront for cloud-based solutions with a contract length of three years or greater (similar to that of a traditional on-premise IT solution) outweigh the cost customers would

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[17] ASC 350-40.
[18] Significant penalty being 10% of the total contract cost.

otherwise be charged if PGE were to pay for cloud-based solutions on an annual, or even monthly, basis at full price. Exhibit 606 provides an analysis illustrating this concept.

Q. Are there other utilities that can rate base license costs associated with cloud-based solutions?

A. Yes. At a minimum, utilities in Alabama, Idaho, Indiana, Michigan, and New York have received state commission approval to rate base costs associated with cloud-based solutions. For further detail, please see Exhibit 607.

Q. Have other utilities requested, but not yet received approval, to rate base license costs associated with cloud-based solutions?

A. Yes. We know of at least two examples. Pacific Gas & Electric (PG&E) requested in their 2023 general rate case (GRC) to rate base prepaid software license costs.[19] In their 2024 GRC, Southern California Gas Company (SoCalGas) also requested to rate base, over a five-year period, prepaid software license agreement costs.[20, 21]

Q. Please summarize why PGE's proposal is a reasonable and effective solution for addressing this issue.

A. By allowing us to include in rate base license and hosting fees associated with pre-paid cloud-based solutions, our proposal addresses the asymmetry in accounting treatment that has created unnecessary complexity and an imbalance of incentives for PGE when considering which IT solutions (on-premise or cloud-based) are best for our business and our customers. This creates consistency and parity between the capital invested in, and treatment of, pre-paid

[19] PG&E 2023 GRC Results of Operations testimony at 10-15 to 10-16, available at: http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=660405
[20] SoCalGas 2024 GRC testimony, at PDM-4 and PDM-5, available at: https://www.socalgas.com/sites/default/files/SCG-31-2R_Second_Revised_Testimony_Rate_Base_2603_2604.pdf
[21] SoCalGas depreciation study noting five-year amortization period, at DAW-55: https://www.socalgas.com/sites/default/files/FINAL_SCG-32-2R_Second_Revised_Testimony_Depreciation_2605_2606.pdf

cloud-based solutions and the traditional on-premise solutions that they are replacing. Our proposal also provides the proper incentive for us to engage in pre-paid contracts for cost-effective cloud-based solutions, which are the better option for PGE and our customers as opposed to more costly monthly or annual payments for cloud-based solutions that do not result in any savings.

B. IT Capital Projects

Q. Please summarize the major IT capital additions since PGE's last general rate case.[22]

A. PGE is implementing new IT systems and programs to replace aging IT infrastructure as our business continues to grow and increasingly requires digital solutions. In support of this effort, PGE's major IT projects that will close to plant by December 31, 2023 total approximately $87.5 million. Table 5 below highlights the five major IT project investments included in this case.

Table 5
Major IT Capital Additions
($millions)

Project	Additions
Enterprise Resource Planning (ERP)	$37.6
Customer to Meter (C2M)	$22.6
Asset and Resource Management (ARM)	$12.6
Digital Channels Uplift	$10.8
Power Operations Risk Transformation (PORTS)	$3.9
Total	**$87.5**

Q. Please elaborate on what is included in the $87.5 million of major IT investments listed above.

A. Major IT investments include:

- $37.6 million related to cloud-based Oracle Fusion Cloud Enterprise Resource Planning (ERP), which is a new software that PGE will use to manage day-to-day

[22] Docket No. UE 394 set rate base amounts as of April 30, 2022.

business activities such as accounting, project management, inventory, and enterprise performance management (EPM);[23]

- $22.6 million related to upgrading Oracle Utilities Customer to Meter (C2M) software, which is the system that PGE uses to manage our customer data, billing, revenue, sales and marketing information, and customer programs;
- $12.6 million related to replacing our outdated ARM tools with state-of-the-art scheduling and field work software as well as substantial upgrades to our existing Maximo system;[24]
- $10.8 million related to integrating our digital customer channels (e.g., Web, Mobile, Intelligent Virtual Assistant (IVA)) into C2M; and
- $3.9 million related to the first phase of our PORTS program, which has been developed to implement critical changes and improvements to PGE's Power Operations and Financial Risk structures, skills processes, tools, systems, and data.

Exhibit 608 provides further details on these capital investments, including the value they will provide to customers, why we chose to make these investments in our IT capabilities at this time, etc.

Q. Please elaborate on the $37.6 million cloud-based ERP investment.

A. For PGE to support our strategic goals, growth, and digital strategy, there is a need to modernize our financial system's infrastructure including process and technology. Our current ERP platform is not readily scalable from process and infrastructure perspectives and does

[23] This figure includes $20.6 million in implementation costs and $17.0 million in prepaid license fees that we were able to capitalize (for further detail, see our discussion on page 23, lines 9 - 18).
[24] Maximo is PGE's enterprise work and asset management system.

not enable PGE to deliver new product and service offerings with the required level of ease and performance monitoring.

The new cloud-based ERP software will be implemented by August 2023 and will be used to manage day-to-day business activities such as accounting, project management, inventory, and performance monitoring. ERP will touch all functions within PGE and will include an effort to complete process reengineering work in several areas as part of the system design. Areas that will realize improvements/efficiencies include financial planning and budgeting control, general ledger accounting, project accounting and asset compliance, payment and distribution, order to cash, financial reporting, and operational reporting and inventory. The new cloud-based ERP will also improve data architecture and data governance at an enterprise level, automate manual processes, and provide PGE the opportunity to decommission some of its on-premise servers without sacrificing performance and disaster recovery support.

Q. Please elaborate on the $22.6 million cloud-based C2M upgrade investment.

A. C2M is the system that PGE uses to manage our customer data, billing, revenue, sales and marketing information, and customer programs. Our current C2M platform is an on-premise solution and is three major software versions/upgrades behind (it has not been upgraded since 2018). Therefore, we are upgrading and migrating our current system onto the cloud-based C2M platform in April 2023 to support our business objective to deliver an integrated digital customer experience. This much-needed upgrade and migration to the cloud will:

- Help provide a performant and flexible foundation to support future customer growth;

- Allow PGE to introduce new customer programs and offerings faster and more cost-effectively than with the prior software version;
- Enable PGE to dynamically scale up and down during critical storm events to protect our customers and ensure we can still bill and collect payments across all customer segments;
- Reduce billing and integration errors and reduce non-PGE labor requirements for customer development and/or testing; and
- Result in a reduction in on-premise hardware purchases and reduce storm-related costs due to cloud scaling abilities during high-demand events.

Q. Please elaborate on the $12.6 million ARM investment.

A. This investment will address two issues. First, it will replace our existing ARM Scheduler and Field Manager tools, which are technically obsolete, with state-of-the-art scheduling and field work software. These new software tools will enable new damage assessment capabilities and provide a tablet-friendly interface with mapping functionality that will improve PGE's ability to respond to large-scale outages across back-office, storeroom, and field workers. Second, this investment will implement several improvements to our existing Maximo work and asset management system, which will ultimately reduce duplicate back-office processing and make crews more efficient. Together, these modernized and improved tools are designed to increase the effectiveness and efficiency of PGE's utility operations, primarily measured by throughput and decreased reliability risks. This is a multi-phase project that is expected to be completed in November 2023.

Q. Please elaborate on the $10.8 million Digital Channels Uplift investment.

A. PGE's Web, Mobile, and Intelligent Virtual Assistant (IVA) digital customer channels have grown over the years to utilize a variety of on-premise and cloud-based solutions, many of which overlap. Further, the back-end systems that support these digital customer channels are several updates/versions behind. To address these issues, this investment will integrate our digital customer channels into the cloud-based C2M platform and leverage core C2M infrastructure to provide a more intuitive experience for our customers when engaging with digital channels, resulting in higher customer satisfaction and reduced call rates. This investment will also provide a foundation for future growth initiatives as a strong, reliable, and scalable platform. This project is parallel to the Oracle Utilities C2M upgrade and is expected to be in-service in April 2023.

Q. Please elaborate on the $3.9 million PORTS phase one investment.

A. The PORTS program is a multi-phase investment developed to implement important changes and improvements to PGE's Power Operations and Financial Risk structures, skills, processes, tools, systems, and data. PORTS will implement new systems and platforms that will automate a handful of legacy systems and error-prone manual processes. PORTS will also:

- Deliver process efficiencies, as well as the data integration and visualization required to manage and deliver PGE's decarbonization goals (e.g., carbon emissions management).
- Create a technology stack required for build-out, maintenance, and operations for PGE's contractual rights for transmission and gas transport.

- Address technology platform improvements that will allow PGE's power operations and IT departments to scale the number of resource integrations into the Energy Imbalance Market (EIM) each year.
- Reduce costs via automation of trading analysts, day-ahead traders and mid-office operations. This mitigation of manual, labor-intensive processes will free up labor resources to focus on other key areas of PGE's business.

The first phase of the PORTS program is expected to be completed in December of 2023.

C. 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 $6.9 million, from $77.9 million in 2022 to $84.8 million in 2024, as shown in Table 6 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 6
Total IT O&M Costs ($ millions)

Category	2021 Actuals	2022 Actuals	2023 Budget	2024 Forecast	2022-2024 Delta
Direct Charges to Operating Areas	$23.4	$25.2	$17.0	$24.0	$(1.1)
Allocated Charges to Operating Areas	$50.2	$41.8	$42.2	$48.2	$6.4
Subtotal IT Incurred	**$73.6**	**$67.0**	**$59.3**	**$72.3**	**$5.3**
Labor Loadings	$13.6	$10.9	$11.1	$12.5	$1.6
Total IT*	**$87.3**	**$77.9**	**$70.4**	**$84.8**	**$6.9**

**May not sum due to rounding*

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

A. As shown in Table 6 above, PGE's IT costs fall into three categories: directly charged, allocated, and labor loadings. 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 609 provides a summary of the direct and allocated charges by operating area.

Q. What do the labor loadings represent?

A. The labor loadings represent payroll-related costs that consist of employee benefits, pension costs, incentives, payroll taxes, employee support, paid time off, and where applicable, injuries and damages. These costs are applied (loaded) based on specific rates per dollar of IT labor. Because the loadings are not specifically IT costs, but instead originate elsewhere and are allocated based on labor, we do not discuss them within IT. Rather, where applicable, these costs are discussed within their originating areas.[25] Finally, PGE submits details regarding its labor loadings as part of its Cost Allocation Manual, which is submitted annually to the Commission as an attachment to our annual Affiliated Interest Report.

Q. What are the major drivers of the forecasted IT O&M cost increase from 2022 to 2024?

A. Several primary drivers affect the variance between 2022 actuals and the 2024 forecast of IT O&M:

- Wage and salary escalations as discussed in detail in PGE Exhibit 500 Section III.B;
- Increased software and hardware license expenses (and associated ongoing maintenance/support expenses) as part of regular year-over-year manufacturer license price escalations as well as increased use of IT licenses in areas of customer service, ERP, and grid management; and
- Increased measures to implement improvements that will strengthen our cybersecurity programs and processes.

[25] Employee benefits, pension costs, incentives, employee support, and paid time off are part of PGE Exhibit 500, payroll taxes are part of PGE Exhibit 200, and I&D costs are part of Section II above.

Q. Does PGE forecast IT labor costs to increase from 2022 to 2024?

A. Yes. IT labor costs are forecasted to slightly increase by approximately 0.2% from $28.6 million in 2022 to $28.7 million in 2024. The following reasons have enabled PGE to achieve operational and staffing efficiencies to keep IT labor costs relatively flat:

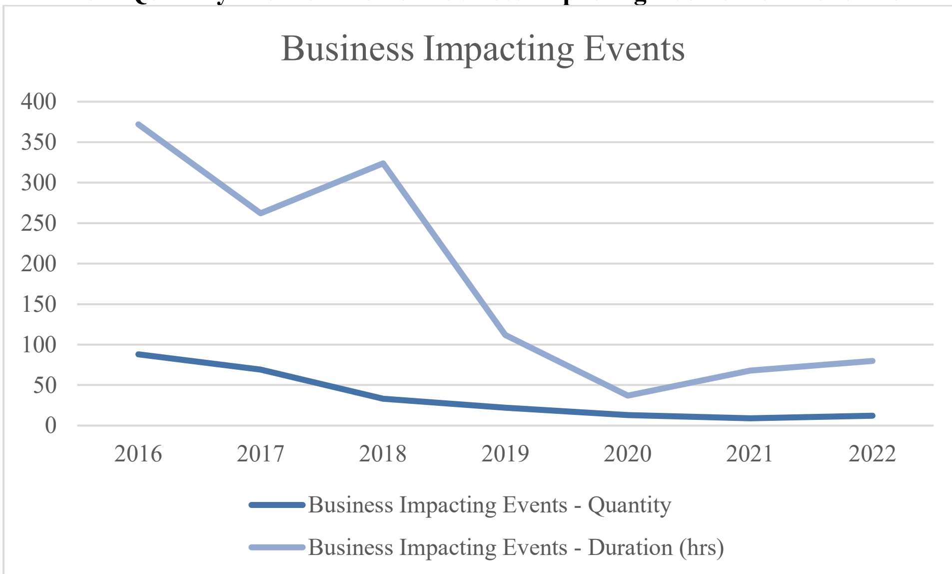
- Process rigor – identifying, fixing, and ensuring that issues don't repeat from a business-impacting event[26] perspective. Cloud-based platforms, such as ServiceNow, enable PGE to track business-impacting events and other requests our IT department handles in an efficient and effective manner;
- Utilizing tools and platforms, many that are cloud-based, that allow us to automate several IT department tasks and reduce the time required to complete certain tasks (i.e., cycle time);
- Proactively working to manage cyber vulnerabilities in a rigorous manner rather than addressing issues after they occur; and
- Resourcing strategy – scaling and offshoring work while keeping our headcount flat, and simplification of our labor landscape by repurposing talent to work on higher priority assignments using the latest technology (i.e., cloud-based solutions).

Q. Do flat IT labor costs lead to reduced performance?

A. No. PGE's IT department has and will continue to leverage the aforementioned efficiencies to reduce the frequency and duration of IT disruptions for customers and across the business for employees. This can be illustrated by our significant reduction in business-impacting events over the last several years as shown in Figure 2 below.

[26] A business-impacting event is a highest-impact, highest-urgency incident that usually affects many employees, customers, or a critical business service with a duration that is unacceptable for normal company operations.

Figure 2
Annual Quantity and Duration of Business Impacting Events from 2016 - 2022



Q. Please elaborate on the improvements that PGE is making to its Cybersecurity team and capabilities.

A. PGE is implementing needed changes and cybersecurity improvements in three key areas - culture, protection, and detection - that are designed to significantly decrease the likelihood of a major security incident. Increasing our focus on the culture of security, education, and supporting processes for managers and employees is designed to greatly reduce misuse or errors resulting in security incidents (e.g., clicking on malicious links, loading unauthorized programs/software which may contain malware, etc.). To improve our defenses, we will leverage expert outside resources that specialize in third-party vendor risk assessments, and we will also complete a significant buildout of operational technology cybersecurity capabilities. We will improve our detection capabilities by enhancing the technology leveraged to identify and detect malicious, anomalous, and potential insider threat activity on PGE's network and assets. Exhibit 610 provides further detail on these and other improvements to our Cybersecurity team and cybersecurity capabilities.

IV. Summary

Q. Please summarize your request for A&G in this filing.

A. We request that the Commission approve PGE's forecast of $209.9 million in A&G costs in the 2024 test year, which represents a $3.5 million decrease from 2022 actuals.

Q. Please summarize your request for IT in this filing.

A. We request that the Commission approve PGE's proposed IT accounting treatment that would allow us to include in rate base applicable license and hosting fees associated with cloud-based solutions. This mechanism proposal will create parity and close any gaps between the accounting treatment of cloud-based solutions and the on-premise solutions that they are replacing.

We also request that the Commission approve PGE's forecast of $84.8 million in IT costs in the 2024 test year. This represents a $6.9 million increase from 2022 actuals, primarily due to PGE's efforts to modernize our IT systems and processes so that they are more resilient, secure, and reliable for our customers.

V. Qualifications

Q. Mr. Ajello, please summarize your qualifications.

A. I joined PGE in 2020, bringing an extensive background in both energy and finance, including over eight years as executive vice president and CFO for Hawaiian Electric Industries (HEI), where I helped lead its clean energy transformation. In 2020, I became an independent director of HEI's Hawaiian Electric Company, where I serve on the Audit Committee. I have also served as senior vice president of Business Development at Reliant Energy, managing director for UBS Financial Services' Energy and Natural Resources Group, and chaired the U.S. Department of Energy's Environmental Management Advisory Board. I earned my bachelor's degree from State University of New York Oneonta, and an MPA from Syracuse University. I am also a graduate of the Advanced Management Program of the European Institute of Business Administration. Finally, I have served on the board of trustees at Hawaii Pacific University for many years and am chair of its Finance and Investment Committee.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
601	Summary of A&G Costs
602	PGE Insurance Policies List
603C	Summary of Insurance Costs
604	Utility Industry Cloud Advocacy
605	PGE Cloud Benefits
606	IT Mechanism Savings Analysis
607	Other Utilities Cloud Capitalization
608	Description of Major IT Capital Projects
609	Direct and Allocated IT Charges
610	Description of PGE Cybersecurity Improvements

A&G Summary - Exhibit	Costs						
	Dec - 2020	Dec - 2021	Dec - 2022	Dec - 2023	Dec - 2024	$ Delta Change	% Delta Change
Major Functional Area							
Accounting/Finance	10.3	12.9	14.0	11.2	15.4	1.4	4.7%
Business Support Services	1.9	1.3	1.4	1.6	1.7	0.3	11.2%
Corp Communications/Public Affairs	3.7	3.3	2.4	2.7	2.8	0.5	9.4%
Corporate Governance	6.8	8.4	8.3	5.9	6.1	(2.2)	-14.1%
Corporate R&D	2.4	2.4	2.6	2.7	3.3	0.8	14.0%
Environmental Services	2.1	3.1	2.2	2.3	2.4	0.2	4.5%
Facilities/Rent	4.6	6.5	4.4	4.4	4.5	0.1	0.7%
Governmental Affairs	1.5	1.6	1.8	1.9	2.2	0.4	10.9%
HR/Employee Support (net of capital allocs.)	10.3	11.9	12.2	11.4	11.9	(0.3)	-1.2%
Hydro Licensing and Support	0.0			0.0	0.0	0.0	#DIV/0!
INSURANCE	11.3	15.6	17.5	16.5	21.7	4.2	11.3%
IT: Direct & Allocated	13.9	15.6	17.3	13.1	17.2	(0.2)	-0.5%
Legal	7.6	11.8	8.7	8.8	9.2	0.5	2.9%
Performance Management	1.5	1.0	0.3	0.4	0.4	0.1	21.3%
Regulation	2.9	2.8	2.6	3.0	3.1	0.6	10.7%
Security and Business Continuity	2.4	2.5	3.4	4.2	4.8	1.4	19.6%
Supply Chain/Contract Services/Purchasing	2.3	2.7	3.6	2.8	3.0	(0.6)	-9.2%
Sustainability and Resource Planning			0.4	0.5	0.5	0.1	11.5%
Subtotal Major Functional Area	85.4	103.3	103.1	93.6	110.4	7.3	3.5%
Other A&G							
Benefits (net of capital allocs.)	50.3	54.6	40.0	47.6	56.2	16.2	18.6%
Corporate Allocations (net)	(8.1)	(0.5)	(2.2)	(7.3)	(5.6)	(3.4)	60.1%
Corporate Cost Reductions				(3.4)	(3.4)	(3.4)	#DIV/0!
General Plant Maint.	2.6	3.1	4.4	3.6	3.7	(0.7)	-8.3%
Incentives	29.6	44.3	42.4	47.9	20.4	(22.0)	-30.6%
LC Fees, Revolver Fees, Margin Net Int., & Broker fees	1.7	3.7	3.2	3.5	2.9	(0.3)	-4.7%
Membership Costs	2.5	2.6	2.6	2.9	2.9	0.3	5.1%
Regulatory Fees	8.3	9.1	10.7	12.1	15.0	4.2	18.1%
Severance	3.8	1.6	1.8			(1.8)	-100.0%
Total Labor Loadings to A&G		0.0	0.0			(0.0)	-100.0%
Total PTO to A&G	5.0	7.2	7.5	7.3	7.5	0.0	0.2%
Subtotal Other A&G	95.6	125.7	110.3	114.2	99.5	(10.8)	-5.0%
Total	181.0	229.0	213.4	207.8	209.9	(3.5)	-0.8%

PGE's Insurance Policies

Insurance Policy	Description
All Risk Property	PGE's main All-Risk property insurance is aquota-share program led AEGIS and 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.
Renewables Property	The All-Risk property insurance program for PGE's renewable assets is currently placed in the London market. Operational All-Risk coverage for these assets, including both wind and solar, are insured to their combined full replacement value of $1.1 billion and carry a $1 million deductible for wind assets and $0.025 million deductible for solar assets.
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 $200 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 603 contains confidential information and is subject to

Modified General Protective Order 23-039.

Information provided in electronic format only.

Industry Cloud Support

National Association of Regulatory Commissioners (NARUC) - 2016

In November 2016, the NARUC, which is an organization whose mission is to serve the public interest by improving the quality and effectiveness of public utility regulation, adopted a resolution in which they encouraged State utility commissions to allow power companies to include cloud-based software investments in rate base and earn a return on said investments.[1]

Edison Electric Institute (EEI) - 2020

In January 2020, U.S. investor-owned utility trade group EEI discussed that regulators should allow capitalization of non-traditional technology assets, specifically noting "A new regulatory approach to capitalizing electric companies' non-traditional investments is necessary to delivering the energy future our customers want and expect."[2]

Information Services Group (ISG) - 2022

In September 2022, ISG, a leading global technology research and advisory firm, released a report (Power and Utilities - Services and Solutions - North America 2022) that discussed trends in the global power and utilities industry.[3] In its report, ISG specifically noted that "Utilities run into unique challenges around adopting cloud-based solutions. For example, subscription costs from cloud service providers have traditionally been categorized as operations and maintenance (O&M) expenses, as opposed to on-premises software licenses and integration efforts, which can be capitalized."

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[1] See NARUC November 16, 2016 "Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements," available at: https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476

[2] Philip D. Moeller, Regulators Should Allow Capitalization of Non-Traditional Technology Assets, ELECTRIC PERSPECTIVES, January/February 2020, pages 42-43, available at: https://lsc-pagepro.mydigitalpublication.com/publication/?m=6643&i=646211&p=44&ver=html5

[3] Swadhin Pradhan, Sandhya Hari Navage, Jan Erik Aase, Executive Summary: ISG Provider Lens Power and Utilities – Services and Solutions – North America 2022, ISG RESEARCH, September 21, 2022, available at: https://research.isg-one.com/reportaction/Quadrant-Power-Utilities-NA-2022/Marketing

Cloud-Based Solution Benefits to PGE

1. Visibility for Customers: PGE's website and mobile application are integral customer communication channels, and are especially critical during storm response, wildfire proactive curtailment, and outages (both planned and unplanned). During outages, cloud-based solutions provide PGE the capability and flexibility to effectively manage these high traffic/demand situations by ramping up and ramping down computing power/capacity as needed. For example, during the February 2021 ice storm, PGE experienced a record number of outages. During this time, our website and mobile application were available to anyone who could access the internet, and the computing capacity required to support increased levels of user traffic was five times the usual amount. If PGE were to build the computing capacity required during the February 2021 ice storm with on-premise solutions, it would require five times the hardware and bandwidth to meet that burst capacity. Moreover, once ramped down, PGE would be left with overbuilt on-premise solutions that would not only sit idle until needed for another high-capacity event but would also require unnecessary ongoing maintenance and support costs.

2. Reliability: Business-critical applications are required for PGE to function, especially during outages. Data is needed for the safety and efficiency of crews to rebuild and repair infrastructure during storms, fires, or other emergencies. During outages, cloud-based solutions provide crews from outside our organization access to our maps and scheduling software, which enables them to efficiently identify their location and complete their work. In 2021, PGE deployed mobile devices to its field crews and contractor crews to provide critical data securely and in real-time. The challenge during an outage is that infrastructure built on-premise in our centers could be affected by that same outage. Cloud-based solutions are located on worldwide networks with massive teams that maintain these networks and ensure connectivity for crews and data availability to customers and PGE in the event that on-premise solutions were to fail.

3. In moving on-premise data warehouses to the cloud, which offers better scalability, data availability, security, and performance, PGE has been able to reduce less-effective on-premise vendor software that is more expensive and more limited in self-service. With the flexibility of separating storage vs. compute with cloud-based solutions, the data and analytics solutions built on the cloud are more scalable and cost-effective for PGE and our customers.

	Contract Amount	Year 1	Year 2	Year 3
Before:	$3,000,000	$1,000,000	$1,000,000	$1,000,000
Price w/ Discount:	$2,628,581	$1,752,388	$876,194	
Return on debt & equity:		$185,709	$123,806	$61,903
Annual depreciation:		$876,194	$876,194	$876,194
After:	$3,000,000	$1,061,903	$1,000,000	$938,097

Discount Required	12.4%

Proposed ROE	9.80%
Proposed Cost of Debt	4.33%
Proposed Cost of Capital	7.07%

	Contract Amount	Year 1	Year 2	Year 3	Year 4	Year 5
Before:	$5,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
Price w/ Discount:	$4,125,583	$3,300,466	$2,475,350	$1,650,233	$825,117	
Return on debt & equity:		$291,472	$233,178	$174,883	$116,589	$58,294
Annual depreciation:		$825,117	$825,117	$825,117	$825,117	$825,117
After:	$5,000,000	$1,116,589	$1,058,294	$1,000,000	$941,706	$883,411

Discount Required	17.5%

Other Utilities That Have Received Cloud Capitalization Approval

New York

In May 2016, the New York Public Service Commission (NYSDPS), in its Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, issued a declaratory statement that utilities could capitalize prepaid contracts for software services.[1] NYSDPS noted, "Rather than developing their own software, many businesses find it more efficient to enter contracts to lease software services over extended periods, typically three to five years. To the extent that these leases are prepaid, the unamortized balance of the prepayment can be included in rate base and earn a return. As utilities evaluate whether to purchase or lease these applications, their ability to earn a return on a portion of the lease investment should help to eliminate any capital bias that could affect the decision."

Alabama

In February 2019, the Alabama Public Service Commission approved Alabama Power Company's application to establish a regulatory asset in which it would capitalize costs associated with software projects, including cloud-based solutions, and then amortize such costs.[2]

Indiana

In December 2019, the Indiana Utility Regulatory Commission approved Northern Indiana Public Service Company's (NIPSCO) proposal to "account for off premise cloud-based technology solutions in the same way that it accounts for on-premise technology solutions."[3] NIPSCO testified that because cloud-based prepaid expenses are expected to provide benefits over extended periods of time and not just in the period in which costs are incurred (similar to capital assets), the prepaid expenses should receive the same regulatory treatment as on-premise solutions and be included in rate base. The specific cloud-based system that NIPSCO included in its proposal had a contract length of five years.

Idaho

In June 2020, the Idaho Public Utilities Commission approved Idaho Power Company's application to defer non-capitalized costs associated with cloud-based solutions, acknowledging that unamortized regulatory asset amounts may be considered for rate base treatment and associated annual amortization expense is eligible for recovery in future rate proceedings.[4]

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[1] See New York Public Service Commission Case No. 14-M-0101, May 19, 2016 Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, at 104, available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bD6EC8F0B-6141-4A82-A857-B79CF0A71BF0%7d

[2] See State of Alabama Public Service Commission, Docket No. U-5285, February 5, 2019 Order, available at: https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=d95be406-0cce-4cb1-8c8a-fdba9ca0e07a

[3] See State of Indiana Utility Regulatory Commission, Cause No. 45159, December 4, 2019 Order of the Commission at 23, available at: https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/ac4c36e7-ae16-ea11-a997-001dd800b582/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45159%20ORDER%2020191204101716836.pdf

[4] See Idaho Public Utilities Commission, Case No. IPC-E-20-11, Order No. 34707, available at: https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2011/OrdNotc/20200625Final_Order_No_34707.pdf

Major IT Capital Investments

Oracle Fusion Cloud Enterprise Resource Planning (ERP) ($37.6 million)

For PGE to support its strategic goals, growth, and digital strategy, there is a need to modernize our financial system's infrastructure including process and technology. The new Oracle Fusion Cloud ERP (ERP) software that PGE will be implementing will be used to manage day-to-day business activities such as accounting, project management, inventory, and enterprise performance management (EPM). ERP will help plan, budget, predict, and report on PGE's financial results. The ERP system will also tie together a multitude of business processes and will enable the flow of data between them.

As we prepare ourselves for increased scalability in the years to come, the new ERP system will replace the outdated and unsupported PeopleSoft Finance and Supply Chain Management (FSCM), PowerPlan budget and project applications, financial reporting tools, and interfaces with other systems such as Maximo[1] and Coupa[2] to provide the aforementioned business activities and functions. The new ERP system is expected to be "in-service" in August of 2023.

ERP will touch all functions within PGE and will include an effort to complete process reengineering work in several areas as part of the system design. Areas that will realize improvements/efficiencies include financial planning and budgeting control, general ledger accounting, project accounting and asset compliance, payment and distribution, order to cash, financial reporting, and operational reporting and inventory. The new cloud-based ERP will also improve data architecture and data governance at an enterprise level, will automate manual processes, and will provide PGE the opportunity to decommission some of its on-premise servers without sacrificing performance and disaster recovery support.

PGE considered alternatives to our new ERP system. The first was to allow the versions of PeopleSoft FSCM and PowerPlan to become more antiquated and accept the risk of operating without vendor support in the near future. The current platform is not readily scalable from process and infrastructure perspectives and does not enable PGE to deliver new product and service offerings with the level of ease and performance monitoring required. The second alternative was to select multiple software solutions to replace PeopleSoft FSCM and move away from an ERP. PGE's integrations between the existing ERP and other financial applications are already complex. Creating new integrations to niche solutions is problematic for data management, reporting, and analytics. This can also be an expensive solution and would require PGE to retain expertise in multiple system's integrations. The third (and selected) alternative was to select a single software solution for integration and efficiency.

Oracle Utilities Customer to Meter (C2M) ($22.6 million)

C2M is PGE's corporate cash register and foundational platform that supports all of our digital channels. More specifically, C2M is PGE's overall Customer Information System (CIS) and consists of our customer care and billing (CCB) modules as well as meter data management

[1] Maximo is PGE's enterprise work and asset management system
[2] Coupa is PGE's source-to-contract, procure-to-pay, and supplier management platform

(MDM). C2M manages all customer information and processes associated with the customer lifecycle. It's the system that enables PGE to manage our customers, revenue, sales and marketing, and customer program management.

Our current C2M platform is an on-premise solution and is three major software versions/upgrades behind (it has not been upgraded since 2018). Therefore, we must upgrade it to support our business objective to deliver an integrated digital customer experience. Without the upgrade, PGE would be unable to support additional growth opportunities in our digital channels. This much-needed upgrade and migration to the Oracle Cloud infrastructure will:

- Help provide a performant and flexible foundation to support future customer growth.
- Allow PGE to introduce new customer programs and offerings faster and more cost-effectively than with the prior software version.
- Enable PGE to dynamically scale up and down during critical storm events to protect our customers and ensure we can still bill and collect payments across all customer segments.
- Reduce billing and integration errors and will reduce non-PGE labor requirements for customer development and/or testing.
- Result in a reduction in on-premise hardware purchases and will reduce storm costs due to cloud scaling abilities.

The C2M upgrade is expected to be "in-service" in April of 2023.

Project Tech Refresh for Asset and Resource Management (ARM) – ($12.6 million)

Maximo is PGE's work and asset management system, which means that Maximo tracks all of our work orders. For example, when a transformer needs to be replaced, a work order is created in Maximo. Then, a scheduler uses the ARM Scheduler tool to schedule the work and assign it to a crew. On that day, a field supervisor will then use the ARM Field Manager tool to view the work order, enter information about the work that's being completed, and then mark it complete. This information then travels back from ARM to Maximo.

These ARM Scheduler and Field Manager tools are technically obsolete and are being replaced with state-of-the-art Maximo scheduling and field work software as part of this investment. This project will also make substantial upgrades to our existing Maximo system. Our current ARM system has significant reliability and security risks and is poorly supported by the vendor, with no roadmap for making ARM more modern, reliable, and secure.

This project will replace ARM Scheduler and Field Manager with Maximo Scheduler for all field crew scheduling, Maximo Mobile for field work in our fences operations (selected teams within Substation and Meter Operations), and IQGeo for field work in utility operations. Because Maximo is already used as PGE's work and asset management system, implementing Maximo Scheduler is a cost-efficient and streamlined option. Functionally it will provide the ability to plan trade work weeks or even months in advance instead of just a few days. Maximo Mobile and IQGeo will provide field workers with much more modern and user-friendly interfaces that work on tablets, making work in the field much more effective and efficient. The IQGeo tool will also provide the ability to see work, outages, and crew locations on a map; the ability to complete damage assessment forms online; and the ability to directly attach photos to a work ticket, all of which will make our outage operations more efficient and help PGE respond to larger events. The project will also implement many improvements to our existing Maximo asset management system, particularly enabling the Multi-Asset Location CI (MALCI) function, which allows multiple poles to be addressed within a single work order. This will reduce duplicate back-office processing and make crews more efficient.

Together these new and improved tools will greatly increase the efficiency and effectiveness of our utility operations, primarily measured by throughput and decreased cybersecurity and reliability risks. The new damage assessment capability, tablet-friendly interface, and mapping functionality will also improve PGE's ability to respond to large-scale outages across back-office, storeroom, and field workers.

This project will be rolled out in phases throughout 2023 and is expected to be "in-service" in November of that year.

Digital Channels Uplift - ($10.8 million)

PGE's Web, Mobile, and Intelligent Virtual Assistant (IVA) digital customer channels have grown over the years to utilize a variety of on-premise and cloud-based solutions, many of which overlap. The Digital Channels Uplift is a parallel project to the Oracle Utilities C2M project and will simplify these systems' architecture and implement the needed building blocks to deliver individual customer experiences and omnichannel experiences across Web, Mobile, and IVA. This project is not replacing any existing systems, but rather will integrate our digital customer channels into C2M and leverage core C2M infrastructure to speed up development and improve quality. Overall, this project will result in an improved front-end interface for PGE customers when using self-service systems for their billing, payment outage, programs, product and energy usage management needs, etc.

The Digital Channels Uplift will provide continuity of existing self-service options available to our customers but with a simpler more resilient and performant backend (i.e., C2M) resulting in reduced customer friction. This is important because there are crucial back-end systems and technologies that are several updates/versions behind. The architecture of these customer-facing systems will be simplified and cloud-based solutions will be leveraged to provide greater resiliency and improve development velocity and quality. Overall, the project will provide a more intuitive experience for our customers when engaging with digital channels, resulting in higher customer satisfaction and reduced call rates.

This project will also provide a foundation for future growth initiatives as a strong, reliable, and scalable platform. The project will upgrade, simplify, and standardize supported in-use technologies which are designed to reduce costs and reduce dependencies on high-value resources for infrastructure and development builds. The expected in-service date for the Digital Channels Uplift project is April 2023.

Power Operations Risk Transformation (PORTS) Program – Phase 1 ($3.9 million)

The PORTS Program is multi-phase and has been developed to implement important changes and improvements to PGE's Power Operations and Financial Risk structures, skills, processes, tools, systems, and data. The Program will support PGE's goal to decarbonize, grow and evolve, and will help meet the changing demands of the Western Energy market. PORTS will also address technology platform improvements that will allow PGE's power operations and IT departments to scale the number of resource integrations into PGE's diverse asset portfolio. As smaller generation assets (i.e., virtual power plant, distributed energy resources, etc.) become available, the work being done through the PORTS Program will enable effective management of these assets through end-to-end value chain.

PORTS will implement new systems and platforms that will automate a handful of legacy systems and error-prone manual processes. PORTS will also:

- Deliver near-term efficiencies, as well as the data integration and visualization required to manage and deliver PGE's decarbonization goals (e.g., carbon emissions management).
- Create a technology stack required for build-out, maintenance, and operations for PGE's contractual rights for transmission and gas transport.
- Address technology platform improvements that will allow PGE's power operations and IT departments to scale the number of resource integrations into the Energy Imbalance Market (EIM) each year.
- Reduce costs via automation of trading analysts, day ahead traders and mid-office operations. This mitigation of manual, labor-intensive processes will free up labor resources to focus on other key areas of PGE's business.

An alternative to the PORTS Program would have been a complete architecture overhaul, but that would have taken significantly longer to implement and at a much higher cost. The first phase of the PORTS Program is expected to be "in-service" in December of 2023.

IT Exhibit 608	a-Dec - 2020	a-Dec - 2021	Dec - 2022	Dec - 2023	Dec - 2024	Delta (Test Year - Base Year)	Annual % Delta (Test Year - Base Year)
Generation							
IT Direct	103,749	20,722	18,573	80,000	83,072	64,499	111.5%
IT Allocated	9,537,622	7,589,446	6,848,962	7,351,919	8,370,993	1,522,031	10.6%
Subtotal Generation	**9,641,372**	**7,610,167**	**6,867,535**	**7,431,919**	**8,454,065**	**1,586,530**	11.0%
Power Ops							
IT Direct	1,826,373	2,451,677	3,468,668	2,897,545	5,990,610	2,521,942	31.4%
IT Allocated	2,383,333	5,738,413	5,849,995	6,338,462	6,915,377	1,065,382	8.7%
Subtotal Power Ops	**4,209,705**	**8,190,091**	**9,318,663**	**9,236,007**	**12,905,988**	**3,587,324**	17.7%
Transm.							
IT Direct	1,176,555	1,198,381	966,708	723,866	1,001,309	34,601	1.8%
IT Allocated	2,174,044	714,644	730,606	713,312	723,346	(7,260)	(0.5%)
Subtotal Transm.	**3,350,599**	**1,913,025**	**1,697,314**	**1,437,177**	**1,724,654**	**27,341**	0.8%
Distr.							
IT Direct	4,138,772	4,964,621	5,925,420	5,202,628	5,842,623	(82,797)	(0.7%)
IT Allocated	7,593,292	13,993,439	6,936,204	6,305,411	7,293,443	357,239	2.5%
Subtotal Distr.	**11,732,064**	**18,958,060**	**12,861,624**	**11,508,039**	**13,136,066**	**274,442**	1.1%
Cust Service							
IT Direct	162,571	98,726	260,273			(260,273)	(100.0%)
IT Allocated	2,434,888	3,015,264	5,118,746	5,194,615	5,890,161	771,415	7.3%
Subtotal Cust Service	**2,597,459**	**3,113,990**	**5,379,019**	**5,194,615**	**5,890,161**	**511,142**	4.6%
Cust Accounts							
IT Direct	11,198,714	16,681,494	12,586,985	13,302,240	14,606,086	2,019,100	7.7%
IT Allocated	12,620,369	12,845,758	10,135,274	10,114,018	11,799,664	1,664,390	7.9%
Subtotal Cust Accounts	**23,819,084**	**29,527,251**	**22,722,259**	**23,416,258**	**26,405,750**	**3,683,491**	7.8%
A&G							
IT Direct	2,118,793	2,727,965	6,062,496	(1,471,364)	798,557	(5,263,939)	(63.7%)
IT Allocated	13,820,687	15,218,119	12,976,405	13,603,629	15,447,685	2,471,279	9.1%
Subtotal A&G	**15,939,480**	**17,946,085**	**19,038,901**	**12,132,266**	**16,246,241**	**(2,792,660)**	(7.6%)
Total							
IT Direct	20,725,528	28,143,586	29,289,124	20,734,915	28,322,256	(966,867)	(1.7%)
IT Allocated	50,564,236	59,115,083	48,596,191	49,621,366	56,440,668	7,844,477	7.8%
Subtotal Total	**71,289,764**	**87,258,669**	**77,885,315**	**70,356,281**	**84,762,924**	**6,877,610**	4.3%

Cybersecurity Improvements

PGE cybersecurity is implementing needed changes and cybersecurity improvements in three key areas: culture, protection, and detection.

The majority of breaches are human-caused; therefore, we will increase our focus on the Culture of Security, education, and supporting processes for managers and employees which will greatly reduce misuse or errors resulting in security incidents. This will include monthly security topics that managers will be expected to cover with their teams and additional awareness and training as needed when security measures and projects that impact employees are deployed (e.g., biometrics for additional login security, data classification maturity, and implementing/upgrading technologies, etc.).

To improve PGE's defenses, we will enhance our Supply Chain Cybersecurity Risk Management program by outsourcing this function to an outside vendor, such as Third-Party Trust, which specializes in identifying third parties that should not have access to PGE systems and data. Leveraging expert outside resources enables our employees to focus on internal risk reduction efforts as we deploy new grid modernization technologies to support decarbonization and transportation electrification. Recognizing the increased dependency on technology to support the grid, PGE is also completing a significant buildout of cybersecurity capabilities in the Operational Technology space that requires ongoing operational costs to support. One such system is Nozomi Networks' Guardian which detects and alerts on suspicious activity in PGE's generation and transmission/distribution networks. Also deployed is Verve Industrial's Security Center which actively detects vulnerabilities and insecure configurations of Industrial Control Systems and other Operational Technology equipment.

The detection capabilities of PGE's Integrated Security Operations Center (ISOC), which is a group/function that operates within the Integrated Operations Center (IOC) and monitors PGE's physical/cybersecurity systems, will improve by enhancing the technology leveraged to identify and detect malicious, anomalous, and potential insider threat activity on PGE's network and assets. This effort will focus on improving the Security Information and Event Management (SIEM) platform capabilities in LogRhythm[1] through the implementation of best practices for logging[2] and rule configuration with expert services and defining a robust process, documentation, and training to keep security resilient with changes in the company. If the number of technical gaps and inefficiencies with LogRhythm as we baseline with best practice goes beyond acceptable levels, we will look to replace it with a new SIEM-like technology in 2024 that will end meet Security Operations Center (SOC) and Network Operations Center (NOC) requirements to further integrate security and IT operation functions to expand monitoring capabilities and allow us to grow our programs of threat hunting and configuration change monitoring. Additionally, we are working to improve our current integration with our Managed Security Services Provider (MSSP). Currently, Accenture, which is the company that is

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[1] LogRhythm is a security intelligence company that is designed to address various cybersecurity threats and challenges with a suite of high-performance tools, such as SIEM.

[2] Logging, or logs, are instances such as user logins and logouts, access to files or systems, network traffic, web filtering, configuration changes, etc. that help audit what is happening on PGE's system or environment.

contracted to perform MSPP services for PGE, has visibility to network security and general infrastructure technologies and therefore is only able to escalate on a fraction of security events that are happening in our environment. Moreover, when a high-log event occurs, our log monitoring services (SIEM and MSPP) could be down for up to a few days, majorly degrading its service. By scaling our infrastructure to handle all high-priority log sources and potential high-log events, our MSSP will be able to provide stable and optimized 24/7 monitoring to maintain a prime response time during non-business hours.

To provide support in the event of a significant cybersecurity incident, we are working to improve PGE's incident response and recovery support services provided by Mandiant, a Cyber Threat Defense Solutions company, who will provide PGE with expert-level support in computer security incident response, digital forensics, log, and malware analysis, and incident remediation assistance. Mandiant's current service level agreement with PGE has no guarantee of a response. We plan to shift to an enhanced pre-paid contract with Mandiant in early 2023 that will guarantee a 2-hour response to requests for service and once both parties have agreed that response services are appropriate, an incident response lead will be assigned within 24 hours.

The risk of not performing these actions increases not only the likelihood of a significant security incident which could lead to the exfiltration of customer data, financial information, or even compromise the systems required to ensure the reliability of the grid but may also limit or significantly delay our response and recovery activities related to those incidents.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Transmission and Distribution (T&D)

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Larry Bekkedahl
Bradley Jenkins

February 15, 2023

Table of Contents

I. Introduction

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

A. My name is Larry Bekkedahl. I am employed by Portland General Electric Company (PGE) as the Senior Vice President of Advanced Energy Delivery.

My name is Bradley Jenkins. I am employed by PGE as the Vice President Utility Operations.

Our qualifications are provided at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to discuss Transmission and Distribution (T&D) capital expenditures from May 1, 2022, through December 31, 2023, and incremental operations and maintenance (O&M) activities and costs for the 2024 test year. We provide additional information about Routine Vegetation Management, grid modernization, and PGE's Distribution System Plan.

Our combined capital and O&M investments will enable PGE to continue implementing its proactive approach to the T&D system to increase the reliability, resiliency, and flexibility needed to enable our customers' clean energy future with a more resilient and integrated grid.

Q. How are Wildfire Mitigation (WM)-related costs treated in this general rate case (GRC)?

A. The treatment of WM-related costs in this GRC is separate from but related to Docket No. UE 412 (UE 412), wherein PGE is seeking approval of a new Schedule 151 WM cost recovery mechanism via an automatic adjustment clause.[1] PGE, Public Utility Commission of Oregon

[1] The full docket name is PGE Advice No. 22-18, New Schedule 151 Wildfire Mitigation Cost Recovery.

(Commission) Staff, and the Alliance of Western Energy Consumers (AWEC) entered into a nonunanimous stipulation (UE 412 Stipulation) to resolve all issues in the docket. The first term in the UE 412 Stipulation requires that in PGE's next GRC (i.e., this proceeding):

> PGE will remove all WM-related O&M costs from base rates and will modify Schedule 151 to include (1) all WM-related O&M costs, and (2) the revenue requirement for prudent WM-related capital placed in service prior to the Schedule 151 rate effective date, consistent with the treatment of capital investments in general rate cases.

The Commission order is not expected until May 2023. Nevertheless, in this proceeding, PGE presumes that the Commission will approve the UE 412 Stipulation in its entirety and without modification. As such, all 2024 O&M amounts and all rate base amounts (including the projected balance of investments previously included in base rates through December 31, 2023) have been isolated within a separate revenue requirement to be removed from base rates in this proceeding and instead collected through a new Schedule 151. Accordingly, all WM-related costs are excluded from Tables 1 and 2 below.

Q. Why did you develop an isolated revenue requirement for WM-related costs in this proceeding?

A. Typically, WM-related costs would be included in our GRC for inclusion in base rates. However, given the pending UE 412 Stipulation that requires us to remove all WM-related costs from base rates in our next GRC, we have developed an isolated revenue requirement for WM-related costs in this proceeding. Provided that the UE 412 Stipulation is approved in its entirety and without modification by the Commission, we will remove the isolated revenue requirement for WM-related costs from base rates and add them to Schedule 151.

Q. What is the isolated revenue requirement for WM-related costs?

A. As shown in PGE Exhibit 200, the isolated revenue requirement for WM-related costs is $33.0 million.

Q. What would happen if the Commission does not approve the UE 412 Stipulation in its entirety and without modification?

A. Absent Commission approval of the UE 412 Stipulation in its entirety and without modification, the isolated revenue requirement for WM-related costs will remain in base rates in this GRC. We will use our next round of testimony immediately following the Commission order to address this and any other changes that are needed.

Q. How is your testimony organized?

A. After this introduction, our testimony is organized as follows:

- Section II: Capital Projects Since UE 394
- Section III: 2024 O&M
- Section IV: Grid Modernization
- Section V: Distribution System Plan
- Section VI: Summary
- Section VII: Qualifications

II. Capital Projects Since UE 394

Q. Why are May 1, 2022, and December 31, 2023, the appropriate beginning and end dates to evaluate T&D and grid modernization investments to be included in rate base?

A. Docket No. UE 394 (UE 394) was PGE's previous GRC wherein rate base was established as of April 30, 2022 and approved by Commission Order No. 22-129. As noted in PGE Exhibit 200, rate base for this GRC is being established as of December 31, 2023, prior to a January 1, 2024, rate effective date.

Q. Please summarize the T&D and grid modernization capital additions (net of WM capital) from May 1, 2022 through December 31, 2023.

A. PGE forecasts investment of $754.8 million in total T&D and grid modernization capital additions for the period of May 1, 2022, through December 31, 2023.[2] Approximately 63.8% of these capital additions are for poles and wires, 26.5% are for substations, and 9.0% are to support our grid modernization efforts. Table 1 below shows the areas of investment over the period.

Table 1
T&D and Grid Modernization Capital Additions
(Net of WM capital)
($millions)

Category	**Additions**
Poles and Wires	$481.2
Substation	$200.1
Grid Modernization	$68.2
Other	$3.8
Communications	$1.5
Gross Plant	**$754.8**

[2] Net of WM capital.

Q. What value will these investments in T&D and grid modernization provide to customers?

A. These investments in T&D and grid modernization provide value to customers by modernizing and securing the grid and its operations to maintain and enhance reliability, leveraging distributed energy resources, accelerating decarbonization, implementing customer solutions to enable rapid electrification of transportation and buildings, and maintaining a safe, reliable, and resilient integrated grid.

Our investments include projects that support additional capacity and flexibility on the system, projects to meet the new and growing load of customers, and projects that replace aging infrastructure and improve safety, all while meeting National Electric Safety Code (NESC) requirements, North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) compliance requirements, and all other applicable standards.

Q. Please discuss the work included in the Poles and Wires category.

A. Poles and wires investments include:

- $233.0 million in poles/towers/fixtures, with nearly three-quarters ($173.1 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.
- $73.2 million in projects to meet customer needs. Projects include 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.

- $72.5 million in blanket T&D projects focused on distribution system construction and upgrades, such as non-FITNES replacement of distribution facilities due to deterioration, including poles, transformers, insulators, pole mounted equipment such as regulators and reclosers, and underground or overhead lines. In addition, work includes safety-focused asset installments or replacements such as inter-set poles to resolve clearance issues, removal of out-of-service assets, and replacement of crowded vaults.
- $45.7 million to replace or upgrade underground cable, driven primarily by the age of the cable, to enhance reliability and mitigate the probability of future failures which could cause injury or damage.
- $27.0 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).
- $18.4 million for reconductor or conversion projects.
- $11.4 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 discuss the work included in the Substations category.

A. Our investments in substations are made to support the 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. Below, we discuss the four projects that exceed $10 million each: Brookwood Substation Conversion; Orenco Substation 115 kV Rebuild; Shute Capacity Addition; and Helvetia Substation Phase 2. These investments are necessary to serve new and growing loads and to maintain a reliable and safe system in compliance with NERC standards.

- **Brookwood Substation Conversion ($60.6 million):** This project is part of the Hillsboro Reliability Project, which includes substation, transmission, and distribution additions and improvements in the Hillsboro area. The purpose of this project is to support industrial, manufacturing, and data center load growth in accordance with NERC compliance requirements. This project converted the 57 kV substation to 115 kV, constructed two new 115 kV lines, upgraded the existing distribution substation transformer, installed a second distribution substation transformer, and constructed new distribution feeders to support increased load growth and maintain reliability. This project was placed in service on December 16, 2022.
- **Orenco Substation 115 kV Rebuild ($29.2 million):** This project is also part of the Hillsboro Reliability Project. The Orenco Substation 115 kV Rebuild improves transmission and distribution reliability and adds distribution system capacity to mitigate heavily loaded equipment and provide operational flexibility. This project addresses a potential NERC compliance issue where the existing Orenco 115 kV breakers could become overdutied once the Evergreen substation is energized. We expect the project to be fully energized in August 2023.

- **Shute Capacity Addition ($23.5 million):** This project installed two new 150 MVA distribution substation transformers at the Shute substation to reliably serve the growing industrial loads in the North Hillsboro area. This project was placed in service on June 10, 2022.
- **Helvetia Substation Phase 2 ($10.9 million):** This project will serve additional load to a large customer under a Minimum Load Agreement; it will add a third and fourth 50 MVA transformer at the Helvetia substation. The expected in-service date for this project is February 24, 2023.

Q. Where is additional information about PGE's investments in grid modernization provided?

A. Section IV provides additional information about our investments in grid modernization.

III. 2024 O&M

A. 2024 O&M

Q. Please summarize the T&D and grid modernization O&M costs for the 2024 test year.

A. As shown in Table 2 below, T&D and grid modernization O&M costs are forecasted to be $207.4 million in 2024, net of WM-related O&M. This represents a $43.7 million increase from 2022 actuals,[3] or a 12.6% annualized increase.

Table 2
T&D and Grid Modernization O&M
(Net of WM-related O&M)
($ millions)

	2022 Actuals**	**2023 Budget**	**2024 Forecast**	**Variance 2022 – 2024**	**Annualized % Increase**
Labor	$82.4	$86.0	$94.2	$11.7	6.9%
Non-Labor	$67.6	$89.2	$98.9	$31.3	20.9%
Labor Loadings	($0.9)	($0.4)	($0.5)	$0.4	(23.7%)
Subtotal	**$149.1**	**$174.8**	**$192.5**	**$43.4**	**13.6%**
Information Technology	$14.6	$12.9	$14.9	$0.3	1.0%
Total O&M*	**$163.7**	**$187.8**	**$207.4**	**$43.7**	**12.6%**

**May not sum due to rounding*
***Adjusted for applicable Level III Outage Accrual Mechanism costs*

Q. What departments are driving the increase between the 2024 forecast and 2022 actuals?

A. Routine Vegetation Management (RVM), apprentice training in utility operations, and grid modernization are driving the increase.[4]

Q. Has PGE included any adjustments for meals and entertainment in its 2024 O&M forecast?

A. Yes. We reduced our meals and entertainment 2024 forecast by $0.5 million, which is approximately 50% of the costs incurred within T&D during 2022.

[3] Net of applicable Level III Outage Accrual Mechanism costs.
[4] Grid Modernization is discussed in Section IV.

Q. What impact did Level III storm costs have on 2022 actuals within T&D and how does that affect the variances shown in Table 2?

A. PGE's 2022 actual T&D expense included approximately $19.7 million of applicable Level III Outage Accrual Mechanism costs. Of these amounts, approximately $10.7 million is classified as labor[5] and approximately $9.0 million is classified as non-labor. As such, a comparison of 2022 actual amounts that included Level III storm restoration costs to the 2024 forecast created the appearance of a lower variance between the years. Thus, in order to create an "apples to apples" comparison between these years, Table 2 has been adjusted to exclude the $19.7 million of applicable Level III Outage Accrual Mechanism costs from 2022 actuals.

Q. What do the labor loadings in Table 2 represent?

A. Amounts included within the labor loadings classification above represent payroll-related costs that consist of employee benefits, pension costs, incentives, payroll taxes, employee support and, where applicable, injuries and damages. For tracking purposes, these loadings are first charged or budgeted to the department and account where the labor is incurred. There is then a corresponding credit to the same account, which effectively returns these costs back to their originating accounts (e.g., benefits, payroll taxes, incentives, etc.). However, the credit amount is recorded within a corporate transfers department used for accounting purposes. As such, when discussing specific department-related costs below, we exclude labor loadings from our analysis.

[5] No straight-time labor costs or associated loadings and allocations are included in PGE's Level III Outage Accrual Mechanism.

B. Routine Vegetation Management

Q. What is driving the increase in RVM?

A. The incremental O&M expense for RVM is $23.6 million, driven primarily by increased cost of outside services (e.g., tree trimming services).

Q. What is PGE's vegetation management strategy?

A. Vegetation management is critical to ensuring a safe, reliable, and resilient system. Our vegetation management strategy has two primary components: our RVM program and our Advanced Wildfire Risk Reduction (AWRR) program. The two programs are complementary with their own requirements and timing.

Q. Please summarize the differences between PGE's RVM and AWRR programs.

A. 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.

In comparison, our AWRR program falls under OAR Chapter 860, Division 300. The AWRR program is specific to High Fire Risk Zones (HFRZ) as defined in PGE's Wildfire Mitigation Plan that is submitted to the Commission for review and approval. Under the AWRR program, PGE performs annual inspections on all overhead line mileage that falls within HFRZ and mitigates identified risks. More information on our AWRR program is available in PGE's 2023 Wildfire Mitigation Plan.[6]

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[6] Filed December 22, 2022, in Docket No. UM 2208.

Q. How are AWRR costs recovered in this proceeding?

A. As described above and pending a Commission order in UE 412, we have developed an isolated revenue requirement for WM-related costs, including AWRR costs, in this proceeding. Assuming the Commission approves the UE 412 Stipulation in its entirety and without modification, the isolated revenue requirement for WM-related costs will be excluded from base rates and instead collected through the new Schedule 151. Prudence review of WM-related costs will occur in a separate process when Schedule 151 is updated and, thus, is not part of this proceeding.

Q. Please describe PGE's RVM program.

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

Our line clearance compliance and FITNES work is driven by 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, or 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. What are the incremental O&M costs for RVM in 2024 compared to 2022?

A. We spent approximately $28.2 million on RVM O&M in 2022. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. What is driving the increase in outside services?

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

Q. Please provide additional information as to why [BEGIN CONFIDENTIAL] [redacted]

A. [redacted]

[redacted] **[END CONFIDENTIAL]**

Q. What is the combined effect of increased need for tree trimming crews across the country and, particularly, in the West?

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

Q. Earlier you said this testimony does not include costs related to wildfire mitigation, yet you are talking about WM-related vegetation management here. Why is that?

A. It is true that we are not including WM-related vegetation management costs in this proceeding. However, the same labor resource pool is required whether the vegetation management is to manage wildfire risk or for reliability and compliance purposes. That is the point: there is increasing need for qualified tree trimmers because of relatively new initiatives (e.g., wildfire mitigation), which further constrains labor availability and results in escalating labor costs.

Q. Please provide some context for the amount and type of vegetation management crews necessary to support PGE's RVM program.

A. Vegetation management jobs that can be accomplished via a bucket truck are generally two-person crews: one foreman and one apprentice or journeyman. The more experienced the crew (i.e., a foreman and a journeyman) the more efficiently work can be completed. Some jobs are inaccessible by bucket truck given the terrain (e.g., too steep, not enough space) and require tree climbing. Any climbing work requires a three-person crew: one foreman, one journeyman, and one journeyman or apprentice. Again, the more experienced the crew, the more efficiently the work can be performed. At the same time, the higher-ranked trimmers command higher wages based on their experience and expertise. Foremen are the most qualified and highest paid, followed by journeymen, and finally apprentices.

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

[END CONFIDENTIAL]

PGE moves its RVM crews off scheduled work when a storm hits so we can remove downed and damaged trees as quickly and safely as possible to restore power to our customers.

Q. [BEGIN CONFIDENTIAL] [redacted]

A. [redacted]

[7] Available at: https://www.bls.gov/data/inflation_calculator.htm
[8] Available at: https://www.bts.gov/data-spotlight/record-breaking-increases-motor-fuel-prices-2022#:~:text=From%20January%20to%20June%202022,%2D19%20(figure%201).

[redacted]

- [redacted] **[END CONFIDENTIAL]**

Q. [BEGIN CONFIDENTIAL] [redacted]

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

C. Apprentice Training in Utility Operations

Q. What is driving the O&M increase in apprentice training in utility operations?

A. We spent approximately $3.4 million on apprentice training in utility operations O&M in 2022. We expect to spend $7.2 million in 2024, which is an increase of $3.8 million. This increase will allow us to support an additional 25 pre-apprentices in this program. We are expanding this program due to the challenges we have in recruiting and hiring qualified line workers, particularly due to our requirement to hot stick, as explained below.

Our apprentice training program enables us to train apprentices from the ground up and create a pipeline of qualified workers for the future. When we have crew shortages, we are forced to supplement with outside contract crews which are more expensive than PGE crews. This apprentice training program creates a pipeline of qualified future line workers, allowing us to keep costs down long term.

Q. What is hot sticking and why does it make recruitment of qualified line workers challenging?

A. Line work apprentices are trained in one of two methods for working on energized lines: hot sticking or rubber gloves. In Oregon, hot sticking is required by the Oregon Bureau of Labor and Industries.[9] Hot sticking is a process to help line crews work safely on energized lines, wherein the line worker uses an insulated fiberglass pole (i.e., "hot stick") to work on energized equipment from a distance. In contrast, much of the rest of the country uses rubber glove work, which is where the line worker makes direct contact with the energized equipment

[9] *See* Oregon Bureau of Labor and Industries, Standards of Apprenticeship, Approved by the Oregon State Apprenticeship and Training Council, revised October 1, 2017, at 24, available at: https://www.oregon.gov/boli/apprenticeship/Standards/1023_0284.0.pdf.

using only rubber gloves. Hot sticking is considered safer because the line worker is further from the energized line and the hot stick is non-conductive. Because other parts of the country do not use hot sticking as extensively as we do in the Pacific Northwest, it is challenging to recruit line workers from outside the area.

When apprentices successfully complete our apprenticeship program, they have one to two years of hot sticking experience and are highly qualified to perform that type of work.

D. 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 against which we charge actual Level III restoration costs as they are incurred. To be 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;[10] 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

[10] 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.

average accrual. This negative balance is set as a hard cap and amounts beyond this cap are not to be included in the mechanism.

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. PGE experienced a number of significant storms during 2022 that increased the current ten-year moving average by approximately $2.7 million resulting in an updated annual accrual of approximately $6.2 million. This increase is summarized in PGE Exhibit 701.

IV. Grid Modernization

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. 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, to provide a bi-directional grid that is reliable, resilient, and secure, and supports our decarbonization efforts. Additional information about PGE's grid modernization framework and initiatives is provided in our Distribution System Plan (DSP).[11]

Q. Please discuss 2024 forecasted grid modernization O&M costs compared to 2022 actuals.

A. We spent approximately $10.7 million on grid modernization O&M in 2022. We expect to spend $14.0 million in 2024, which is an increase of $3.4 million.

Q. What is the driving the $3.4 million increase in grid modernization O&M costs?

A. The increase in grid modernization O&M costs is driven by filling positions that were included in the last GRC but have gone unfilled due to a tight labor market for the required skillsets and adding eight new positions: four to support the operations of the Virtual Power Plant (VPP) desk and four to support operational technology infrastructure, database needs, and production support associated with the Advanced Distribution Management System (ADMS) needed to implement the VPP platform and other key grid modernization initiatives.

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

Q. What is the Virtual Power Plan (VPP)?

A. The VPP is comprised of DERs and flexible loads that are managed through a technology platform to provide grid and power operations services. DERs include generation resources (e.g., distribution-connected solar and customers' dispatchable standby generators (DSG)) and energy storage (e.g., stand-alone batteries and electric vehicles); flexible loads include demand response.[12]

Q. What is the current state of PGE's VPP?

A. As of December 2022, we had approximately 230 MW of resources included in our VPP.[13] This includes DERs and flexible loads that can be manually and semi-automatically dispatched to provide three services: frequency response, contingency reserves, and load reduction. In 2022, we utilized our DERs and flexible loads to provide those services for a total of 139 events, including reducing peak loads and regional grid needs.

Q. What is the future state of PGE's VPP?

A. The evolution of our system includes significant growth of DERs and flexible loads, a long-term trend which is accelerated by state and federal policy including House Bill (HB) 2021 and the Inflation Reduction Act of 2022. The VPP is a cornerstone of our vision for providing clean, reliable, and affordable energy.

The progression of the VPP will enable DERs and flexible loads to provide enhanced time- and location-specific benefits. As the capabilities of the VPP platform are implemented,

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

[13] Includes 130 MW of DSG (primarily customer-owned sites), 92 MW across all demand response programs, and 8 MW of distributed energy storage (consisting of PGE's Port Westward battery, Beaverton Public Safety Center microgrid, and Salem Smart Power Center).

and the size of our DER and flexible load portfolio grows, the VPP will increasingly be able to deliver additional benefits. Over time, the number of VPP operations will grow from the 139 events in 2022 to many thousands and eventually millions as we go from discrete event operation to real-time energy management. Building a scalable VPP platform is the next incremental step in our distribution system transformation from a one-way grid to a bi-directional grid.

Q. How does the VPP provide value to customers?

A. The VPP is an important tool for identifying and extending DER and flexible load benefits to our customers and community partners who seek equitable local clean energy investments. Through the VPP, DERs and flexible loads can help us achieve cost-effective decarbonization, advance customer and community energy resiliency, promote customer engagement with the energy system, and unlock additional grid services that enable our DSP vision of a dynamic bi-directional system.

Q. What is the role of a VPP platform in scaling the VPP?

A. We are currently working towards acquisition and implementation of a VPP technology platform that will integrate with our ADMS and Energy Management System (EMS) along with the various internal systems located in the Integrated Operations Center (IOC). The VPP platform is an enhanced computing solution that provides real-time visibility and control of generation, flexible loads, and batteries residing within the distribution network. The VPP platform will:

- Provide the necessary functions for centralized aggregation points which govern the availability, capability, and reasonability of dispatching sets of DERs and flexible loads to deliver grid services;

- Host the rules algorithm that manages priorities with respect to capabilities of the underlying resources and/or customer programs;
- Provide insights to the current state of resources in real-time, such as device availability, state of charge, or level of generation; and
- Provide data on resource and load utilization to better inform resource planning with improved analytics.

By integrating the VPP platform with PGE's ADMS and EMS and following the resource-specific capabilities outlined in plant parameter sheets, the platform will let us dynamically aggregate and disaggregate DERs and flexible loads into portfolios that mimic the operational characteristics of traditional power plants based on the grid services needed, thus allowing our operators to call on such portfolios to provide various grid services while ensuring compliance with the varying requirements of underlying resource capabilities and customer programs.

Q. Is the VPP platform included in this proceeding?

A. No. We are working to acquire and implement the VPP platform this calendar year and expect to place the VPP platform service during the first quarter of 2024; therefore, we will include the capital costs for the VPP platform in our next GRC.

Q. Are there any VPP O&M costs included in this proceeding?

A. Yes. Because we expect the VPP platform to be in service within the first quarter of 2024, we have included O&M costs necessary to implement and operate the VPP platform in 2024, including the aforementioned four incremental positions and consulting support necessary to begin integrating the VPP platform into operations.

Q. Why are the VPP operator positions necessary to advance VPP capabilities?

A. Like the control room of a conventional power plant, where operators monitor status in real time, adjust output, and troubleshoot issues, operators need tools to monitor and control VPP operations. Via the VPP platform, operators will have:

- Improved visibility to the location and status of distributed resources;
- Improved connectivity with the advanced distribution network;
- Improved market connectivity and accelerated event data analytics; and
- Improved delivery of grid services through automated orchestration.

Ultimately, the operators and the platform will enable our VPP to orchestrate the operations of a significant number of DERs and flexible loads, allowing them to function as a single power plant and with a higher degree of flexibility than a traditional power plant.

Q. Please discuss the key capital investments PGE is including in this proceeding to support its grid modernization initiative.

A. This proceeding includes $68.2 million of capital investments to support our grid modernization initiatives. Key investments are summarized below:

- **Phase 2 at the IOC[14] ($22.1 million):** Phase 2 will install a microgrid consisting of solar generation (rooftop solar plus parking canopies with embedded solar panels), 14 additional electric vehicle charging stations, and battery storage. This microgrid will provide enhanced resiliency and reliability to this critical infrastructure, while further decarbonizing our system. Phase 2 is expected to be placed in service in July 2023.

[14] The IOC was placed into service in 2021 and was included in our last GRC. The IOC centralizes all mission-critical operations to maintain the flow of power to customers and is a critical part of PGE's strategy to deliver the reliable, resilient, affordable clean energy future our customers need and expect.

- **Distribution Automation ($17.8 million):** Distribution Automation includes new field Supervisory Control and Data Acquisition (SCADA) devices that encompass a variety of control and monitoring strategies to optimally manage the distribution system, including increased awareness and proactive reconfiguration, allowing PGE to reduce restoration time and risk on the system, and resulting in a more reliable distribution system for customers with fewer sustained outages. PGE expects to install approximately 135 SCADA reclosers on distribution mainline feeders to enable deployment of Fault Location, Isolation, Service Restoration (FLISR) schemes. Substation upgrades are also needed to accommodate automated FLISR in ADMS.
- **Field Area Network (FAN) Project ($6.5 million):** FAN is a PGE-owned and operated wireless network that enables wireless communication between distribution assets in the field and the IOC. FAN offers substantial benefits compared to alternative communication networks by providing improved reliability and restoration due to less reliance on third-party network providers; increased availability of field sensor data and control devices; resilience through increased security and encryption; and enhanced data analytics, including greater visibility into customer demand for electricity. Distribution Automation is the first application of PGE's FAN, connecting automated reclosers to the ADMS. FAN began carrying live traffic in July 2022 and we are continuing to expand coverage through 2025 to efficiently operate the grid and serve our customers.
- **ADMS Phases 1 and 2 ($4.0 million):** The ADMS platform provides visibility into and control of the distribution grid. ADMS Operational Go-Live (OGL) occurred in March 2022, with the commensurate capital outlay included in PGE's last GRC.

To achieve that OGL date, PGE accepted a post-OGL patch from the vendor to provide functionality that was unable to be placed in service by the OGL date. This enabled the ADMS to be safely and reliably placed into service in March 2022, allowing PGE to begin realizing the benefits of ADMS while the vendor addressed the remaining issues. Phase 2 provided additional configurations to integrate ADMS with other systems and further enhance the operationality of ADMS. The ADMS platform, Phases 1 and 2, was fully functional as of December 2022.

- **ADMS Conservation Voltage Reduction (CVR) Volt VAR Optimization (VVO) ($3.8 million):** This project provides improved voltage control and capacity utilization of feeders through upgrades of load tap changer (LTC) control and deployment of distribution line capacitor banks. The LTC control upgrades will enable SCADA control of the LTCs which will support control of feeder source voltage by our distribution system operators and ADMS. The capacitor banks and LTC controls will be controlled by the ADMS and will support greater penetration of DERs on our system.
- **Grid Log Automatic Standardization System (GLASS) ($2.9 million):** GLASS is an automated and standardized logging system for operations logs within grid operations that replaced our previous approach of non-standardized, manual reporting using Microsoft products. GLASS's functionality makes it easier to search logs and meet compliance and auditing requirements. GLASS was placed into service in November 2022.

V. Distribution System Plan

Q. What is the Distribution System Plan?

A. The Distribution System Plan (DSP) is the plan PGE files with the Commission based on the guidelines adopted in Order No. 20-485. The Commission's goal of the DSP and associated stakeholder processes is to develop a "transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."[15]

Q. Has PGE filed its initial DSP?

A. Yes. Pursuant to the guidelines adopted in Order No. 20-485, PGE developed and filed its initial DSP in Docket No. UM 2197 in two parts: Part 1 in October 2021 and Part 2 in August 2022.

Q. How does the initial DSP advance PGE's strategy and vision?

A. Through the DSP, PGE has articulated a vision of a 21st century community-centered distribution system by advancing environmental justice, accelerating DERs, and maximizing grid benefits. The DSP describes five strategic initiatives to empower our communities, modernize the grid, ensure resilience, provide "plug and play" access to the distribution system, and partner with the Commission to evolve regulatory frameworks needed to achieve these initiatives. The DSP also provides details and transparency on PGE's processes to analyze grid needs and identify solutions.

Q. What are the benefits of the DSP to PGE customers and local communities?

A. The DSP provides PGE customers and local communities with a human-centered approach to identify grid needs, create value-add investments for communities, and align the energy

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[15] *See* Docket No. UM 2005, Order No. 19-104, Appendix A at 1, available at https://apps.puc.state.or.us/orders/2019ords/19-104.pdf.

system with community priorities. By making utility planning more customer-inspired and community-centric, PGE's DSP puts forward the action plan to realize the benefits of a modernized grid with improved security, resilience, and renewable integration.

Q. Please describe the stakeholder process PGE conducted during the development of its inaugural DSP.

A. PGE is committed to transitioning to a human-centered planning approach and has built the DSP on a foundation of engagement with the broader community (partners, customers, and communities). PGE conducted 23 workshops between January 2021 and August 2022 as we developed DSP Part 1 and Part 2, including workshops led by community-based organizations. PGE's DSP Community Engagement Plan was developed and informed by recommendations and learnings that resulted from the community workshops and includes best practices provided by our community partners.[16] To provide additional transparency and to support education and engagement with our communities, PGE's DSP website provides all workshop materials, recordings of the workshops, and links to additional sources with educational information.[17]

Q. Upon utility submission of its DSP, what actions may the Commission take?

A. Section 2 of the DSP Plan Guidelines adopted in Order No. 20-485 states that the Commission will consider whether to accept the filed Plan (or Plan Part). The Guidelines state that "'acceptance' means the Commission finds the Plan meets the criteria and requirements of these Guidelines. Acceptance does not constitute a determination on the prudence of any individual actions discussed in the Plan." The Commission may choose to "not accept" the

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[16] *See* Distribution System Planning Part 1, Appendix H, available at: https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning/dsp-resources-materials
[17] *See* https://portlandgeneral.com/dsp

Plan upon the finding that "the Plan does not meet the criteria or requirements of the Guidelines."[18]

Q. Has the Commission taken action in response to PGE's DSP Part 1 and Part 2 filings?

A. Yes. In Order No. 22-083, the Commission accepted PGE's DSP Part 1 filing as meeting the objectives of the DSP Guidelines estimated in Order No. 20-485. The Commission has yet to take action in response to PGE's DSP Part 2, but we expect that to occur in the first quarter of 2023.

Q. What is the relationship between the DSP and this rate proceeding?

A. The DSP provides increased accessibility and responsiveness of the utility distribution planning processes to stakeholders. The DSP discusses capital investments that PGE may or will make in the future but is not a project-level prudence review or a cost recovery proceeding and does not include O&M for future investments. In contrast, this GRC is a cost recovery proceeding, including prudence review, to specifically discuss capital projects that have been placed in or are forecasted to be placed in service between May 1, 2022, and December 31, 2023, and O&M costs forecasted for the 2024 test year. To the extent projects discussed in the DSP fit those criteria, they are included in this GRC.

DSP Part 1 and Part 2 filings included the best information available at that time, as does this GRC. However, the vintages of the information vary; for example, this GRC was developed more than six months after the DSP Part 2 was filed.

Order No. 20-485 states that the "PUC recognizes the need for ongoing conversations about how DSP activities align or interact with the utilities' existing business models and

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[18] Docket No. UM 2005, Order No. 20-485, Appendix A at 14.

regulatory approaches" and that after utilities submit initial Plans, "Staff will engage with utilities and stakeholders to explore how new regulatory mechanisms may support DSP in the future."[19] We expect those conversations to continue in the DSP regulatory process.

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[19] *Id.* at 8.

VI. Summary

Q. Please summarize your testimony.

A. PGE continues to invest in a resilient and reliable T&D system that supports our goal of decarbonization and grid modernization. These are multi-year efforts to replace aging infrastructure and serve growing loads, modernize, and secure the grid, leverage DERs and flexible loads, support electrification of transportation and buildings, and provide increased visibility and bi-directional communication in our increasingly complex distribution system. Part of maintaining a reliable T&D system is running a RVM program, per Division 24 Safety Standards, despite historic labor shortages and rising labor costs.

We forecast 2024 O&M costs to increase by approximately $43.7 million compared to 2022 actuals of $163.7 million.[20] The primary drivers of these O&M cost increases are RVM, apprentice training in utility operations, and grid modernization. PGE's total T&D and grid modernization capital additions for May 1, 2022, through December 31, 2023, are $754.8 million,[21] the vast majority of which is for poles and wires and substations necessary to maintain reliability of an aging system and meet growing customer needs.

We have developed an isolated revenue requirement for WM-related costs in this proceeding. Provided that the Commission approves the UE 412 Stipulation in its entirety and without modification, those costs will be removed from base rates and added to the new Schedule 151. Should the Commission not approve the UE 412 Stipulation in its entirety and without modification, the isolated revenue requirement for WM-related costs will remain in

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[20] Net of WM O&M and net of applicable Level III Outage Accrual Mechanism costs.
[21] Net of WM capital.

base rates in this proceeding, and we will use the next round of testimony after the UE 412 Commission order to address any other changes that are needed.

VII. 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, Common Ground Alliance (811 call before you dig), 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. Jenkins, please describe your qualifications.

A. I hold a Bachelor of Science degree in Industrial Engineering from Southern Illinois University and have over 25 years of nuclear and thermal generation plant experience in operations, maintenance, refueling, and construction. I am a certified Project Management Professional and have worked for Entergy, Energy Northwest and contracted with Tennessee Valley Authority. I joined PGE in 2012 as Operations Manager at the Boardman coal plant and became the plant manager in 2013. I was promoted to General Manager, Diversified Plant Operations in 2014, overseeing all of PGE's thermal and renewable assets in eastern Oregon and Washington. In September 2015, I became Vice President of Power Supply Generation, in October of 2017, I was appointed Vice President of Generation and Power Operations, and in 2020 I was appointed Vice President of PGE Utility Operations. Today, I oversee our distribution line operations, and over 3,000 MWs of wind, solar, hydro, and thermal generation at 17 generation facilities, as well as the Trojan Independent Spent Fuel Storage Installation (ISFSI).

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
701	Level III Storm Accrual

2008 - 2022 Actual Level III Storm Damage Losses

CPI	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
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	8.14%	8.14%	8.14%	8.14%	8.14%	8.14%	8.14%	8.14%	8.14%	8.14%	8.14%	8.14%	8.14%	8.14%	$ 19,853,552
2023	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%	4.26%
2024	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%	2.71%
2024$	$8,652,692	$ 3,080,427	$ -	$ -	$ -	$ -	$ 7,454,435	$ 6,834,447	$ 5,888,700	$ 14,531,287	$ -	$ 2,175,237	$ -	$ 4,162,049	$ 21,259,980

Ten Year Total Level III Storm Damage Losses	$ 62,306,135
Ten Year Avg Level III Storm Damage Losses	$ 6,230,614
Average Level III Storm Damage Losses	$ 8,900,876

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	$ 19,853,552	8.14%
2023		4.26%
2024		2.71%

	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	$ 3,804,696	$ 19,853,552	$ -

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Production

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Larry Bekkedahl
Bradley Jenkins

February 15, 2023

Table of Contents

I. Introduction

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

A. My name is Bradley Jenkins. I am employed by Portland General Electric Company (PGE) as the Vice President of Utility Operations. My qualifications appear at the end of PGE Exhibit 700.

My name is Larry Bekkedahl. I am employed by PGE as the Senior Vice President of Advanced Energy Delivery. My qualifications appear at the end of PGE Exhibit 700.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support the operation and maintenance (O&M) expenses associated with PGE's long-term power supply resources. We discuss the recent plant performance of our generation fleet. We also identify and discuss the major drivers of the 2024 test year O&M expenses related to PGE's generating plant operations as compared to actual 2022 O&M expenses. Finally, we discuss projects such as our Faraday Resiliency and Repowering and other major capital projects.

Q. How is the remainder of your testimony organized?

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

- Section II: Generation resources and plant performance;
- Section III: 2024 test year generation O&M expenses;
- Section IV: Major Maintenance Accruals (MMAs);
- Section V: Faraday Resiliency and Repowering Project; and
- Section VI: Summary.

II. PGE's Generation Resources

A. Generation Resources

Q. Have you prepared an exhibit that identifies all of PGE's power supply resources for the 2024 test year?

A. Yes. Confidential PGE Exhibit 801 lists PGE's generating resources and their expected average energy output as modeled under normal conditions for PGE's initial 2024 Net Variable Power Cost (NVPC) forecast.

Q. Is PGE adding any generation resources to its portfolio in 2024?

A. Yes. PGE currently expects the Clearwater Wind facility to provide service to customers in 2024. However, we are in the beginning stages of forecasting the expected costs and benefits of this project. As such, we expect to file a request under PGE's Schedule 122, Renewable Resources Automatic Adjustment Clause, sometime during the third quarter of 2023 to include all expected costs and benefits from the project into customer prices, consistent with the online date of the facility.

Q. Is PGE currently performing major upgrades to any generation facility?

A. Yes. PGE's major generation upgrade projects currently include the Beaver Emissions Reduction Program and the Biglow and Tucannon Wind Enhancement Programs. Additionally, the Faraday Resiliency and Repowering Project became used and useful for customers on January 31, 2023. We provide details about this project in Section V.

Q. Please briefly describe the Beaver Emissions Reduction Program.

A. PGE's Beaver 500 MW combined-cycle natural gas plant and 24.8 MW steam turbine provide important dispatchable generating capacity, helping to integrate renewable energy supplies while also ensuring reliable electric service for PGE customers, particularly during peak demand hours. In order to keep this plant operating reliably within emission requirements, upgrades to modernize the plant are necessary. Work on the Beaver Emissions Reduction Program is planned to be completed in the coming years and will entail upgrading the existing natural gas turbine combustion systems from a dual fuel system to a single fuel dry low nitrogen oxide (NOx) system, reducing the overall emissions for the plant as the turbines are upgraded. The upgraded units will operate on natural gas as the fuel source. The combustion upgrade will allow for greater availability and reliability while meeting PGE's commitment to reduce emissions at the Beaver plant. The capital investment associated with the upgrades that is expected to close to plant by December 31, 2023, is $56.9 million.

Q. Why is PGE converting the Beaver gas turbine combustion systems?

A. Beaver is subject to the Oregon Department of Environmental Quality's (DEQ) enforcement of the Regional Haze Program, which implements the federal Clean Air Act's Regional Haze Rule.[1] In August 2021, DEQ issued an order requiring PGE's compliance with annual plant site emissions limits of Regional Haze pollutants.[2] Environmental regulations and emissions reduction requirements have increased over time, as have the environmental stewardship expectations of PGE customers and stakeholders. The post-project NOx emissions rate will be significantly lower with an approximately 90% reduction, based on design conditions. Additionally, this project will modernize the turbines, extending their life.

Q. Please describe the Biglow Phase I Wind Enhancement Program.

A. This program will address equipment wear-and-tear impacts that affect wind turbine performance over time. The purpose of this project is to maintain performance through the

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[1] *See* 40 CFR § 51.301 and OAR Chapter 340 Division 223. DEQ's Regional Haze: 2018-2028 State Implementation Plan: https://www.oregon.gov/deq/rulemaking/Pages/rhsip2028.aspx

[2] *See* DEQ Emissions Order: https://www.oregon.gov/deq/aq/Documents/SAFOPGEBeaver.pdf

operating life of the project. The capital enhancement plan includes replacement of pad mount transformers, pitch and yaw systems, blade and main bearings, gearboxes, and generators on 13 turbines per year starting in 2023. This option was selected as the preferred approach when compared to repowering because it results in a lower customer cost impact, better economics (based on levelized cost per MWh), and reduced interruption to facility operations. The amount expected to close to plant in 2023 is $7.3 million.

Q. Please describe the Tucannon Wind Enhancement Program.

A. The Tucannon Wind Enhancement Program responds to a defect issue with Siemens 2.3 MW turbines, where their 108-meter blades experience cracking, delamination, and leading-edge erosion issues. Today, approximately nine years after plant construction and well past the end of the warranty period, Tucannon is experiencing site-wide blade issues due to the previously mentioned defects, which PGE has been actively managing. This issue was not evident prior to the end of the warranty period. In order to mitigate risks associated with this defect, PGE decided to employ a capital enhancement plan, which consists of installing blade strengthening retrofits, leading edge erosion protection, and replacement pitch cylinders. During 2023, PGE expects to replace the pitch cylinders on at least 50 turbines and install leading edge protection on the blades for the entire facility. This option was chosen as opposed to repowering because it results in a lower customer cost impact, better economics (based on levelized cost per MWh), and reduced interruption to facility operations. The expected amount to close to plant for 2023 is $1.7 million.

B. Plant Performance

Q. What are PGE's goals for generation plant O&M?

A. Our primary goals for plant-related expenditures are to maintain and operate our generating plants in a safe, reliable, and efficient manner, while maintaining compliance with all local, state, and federal laws, regulations, permits, licenses, and environmental standards. We achieve these goals by implementing prudent maintenance practices, establishing effective safety and reliability initiatives, and making necessary investments in our plants.

Q. How did PGE's gas plants perform in 2022?

A. In 2022 PGE's gas plants continued to perform well. Overall, the gas generation fleet maintained an average availability of 88.7% in 2021 and 85.9% in 2022.

Confidential PGE Exhibit 802 provides historical 2020 through 2022 gas plant availability.

Q. How does the 2024 expected generation for PGE's gas plant resources compare to previous years?

A. Confidential PGE Exhibit 803 provides actual gas plant generation for 2020, 2021, 2022, and PGE's current 2024 forecast for each of our gas resources. Gas generation is expected to increase in 2024 relative to 2022 due to an increased forecast dispatch of our gas plants based on economics. PGE Exhibit 300 provides PGE's 2024 initial NVPC forecast and supporting documentation regarding the MONET forecasted economic dispatch of PGE's gas plants.

III. Generation Plant O&M

A. Generation Plant O&M Expenses

Q. What is your 2024 test year forecast of generation O&M expenses?

A. Our test year forecast of generation O&M expenses is approximately $112.6 million excluding Information Technology (IT) costs. This represents an $10.7 million increase over 2022 actuals. Table 1 below summarizes these costs.

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

O&M Expenses	2022 Actuals	2024 Test Year	Delta	Annual % Change
Labor	$39.0	$38.0	($1.0)	-1.3%
Non-Labor	$42.9	$48.9	$6.0	6.7%
Major Maintenance Accrual	$13.3	$18.6	$5.3	18.3%
Plant Subtotal	**$95.2**	**$105.5**	**$10.2**	**5.2%**
Environmental Services	$6.7	$7.1	$0.4	3.0%
Sub-Total	**$102.0**	**$112.6**	**$10.7**	**5.1%**
Information Technology (IT)	$16.2	$21.4	$5.2	14.9%
Total	**$118.1**	**$134.0**	**$15.8**	**6.5%**

** 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 2024 test year, aside from Schedule 145 decommissioning costs.*

Q. How are labor and non-labor generation O&M expected to change from 2022 actuals to the 2024 forecast?

A. We project labor-related generation O&M to decrease in 2024, as shown in the table above. Overall PGE labor is discussed in PGE Exhibit 500, and we discuss labor-related plant generation O&M in Section III.B.2, below. We project non-labor-related plant generation O&M, with IT expenses excluded, to increase by approximately $11.3 million in 2024. This figure can be found below in Table 2.

Q. Why are non-labor costs increasing from 2022 actuals to the 2024 forecast?

A. PGE is facing higher than usual price escalations on services and materials that are essential to delivering safe and reliable power to customers. From chemicals needed to meet environmental standards to material costs for reliability-ensuring repairs, we continue to experience inflationary impacts on items that are necessary to provide consistent service for our customers. On top of escalations, non-labor costs are also increasing because of additional maintenance that will occur over the next few years to ensure energy security for PGE's customers into the future.

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 600.

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 2022 to 2024?

A. With IT expenses omitted, non-labor plant O&M expenses from 2022 to 2024 will increase by an estimated $11.3 million. This change is reflected below in Table 2.

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

Operating Area	2022 Actuals	2024 Forecast	Delta 2022 vs. 2024	Annual % Change
Gas-Fired Plants	$14.8	$19.8	$5.0	15.8%
Hydro Plants	$5.3	$3.9	($1.4)	-14.1%
Wind Plants	$15.7	$17.5	$1.8	5.5%
Major Maintenance Accrual	$13.3	$18.6	$5.3	18.3%
General and Miscellaneous	$7.1	$7.6	$0.5	3.7%
Environmental	$3.8	$3.8	($0.0)	-0.2%
Sub-Total	**$60.1**	**$71.3**	**$11.3**	**9.0%**
IT Expenses	$11.0	$15.1	$4.1	17.1%
Total	**$71.1**	**$86.5**	**$15.4**	**10.3%**

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

Q. What are some specific drivers for the changes in non-labor plant generation O&M expenses between 2022 actuals and 2024 forecast?

A. The primary drivers for the change in non-labor O&M expenses are:

1) An increase in non-labor cost escalations. In particular, escalations for outside services, which are crucial for essential maintenance activities, are forecast to increase by approximately 5% in 2023 and nearly 4% in 2024.[3]
2) An increase of approximately $5.0 million in gas plant operations mainly due to increased maintenance costs expected to occur in 2023 and 2024. These increases stem from additional maintenance necessary to ensure plant reliability, as well as increasing costs for outside services and other materials and equipment.
3) An increase of approximately $1.8 million related to wind plant operations, due to annual escalation of Long Term Service Agreement (LTSA) costs at PGE's Biglow and Tucannon wind generation facilities.
4) A decrease in hydro plant operations due to a 2022 project cancellation and maintenance that is not applicable in 2024.
5) An increase of $5.3 million in Major Maintenance Accrual (MMA) O&M expenses. However, when considering total MMA expense included in both Generation O&M and Other Revenue accounts, the net increase from 2022 actuals to the 2024 GRC revised total amounts to approximately $1.8 million.[4] MMAs are covered in more detail in Section IV below.

[3] As forecast in the *IHS Markit*, Long-term Forecast dated August 2022.
[4] *See* Exhibit 804, cell E8.

Gas Plants

Q. Please provide more detail regarding the increase to non-labor O&M at PGE's gas plants.

A. The $5.0 million increase referenced above is being driven by three primary factors:

1) Non-labor cost escalations. Inflation hit its highest point in a generation during 2022 and while this high point has tapered off somewhat, we are expecting higher than average inflation over the near term. PGE's escalation rates applied to outside services are 4.95% in 2023 and 3.84% in 2024. See PGE Exhibit 200 and PGE Exhibit 600 for more detail regarding 2024 forecasted rates.

2) An approximate $2.7 million increase to costs associated with maintenance work at Beaver and Port Westward 1 & 2 (PW1 & PW2) as part of the plants' annual maintenance outages, necessary for certain generation plant upgrades. This increase to maintenance costs is necessary to ensure the continued reliability of PGE's gas plant fleet.

3) Approximately $0.3 million associated with chemical cost increases at Coyote due to increased plant availability and supply chain complications that increased the base price. Specifically, sulfuric acid and sodium hypochlorite costs at Coyote, have experienced price increases above 50% from 2021 to 2022 and we expect this market trend to continue into 2024. Note that these chemicals are not included in PGE's NVPC.

Q. Can you provide more specifics regarding the increase to Beaver, PW1 and PW2 maintenance costs?

A. Yes. The key aspects of this incremental maintenance work are as follows:

- Beaver:
  - VF4 step up transformer refurbishment for Beaver Unit 7 to address risk and extend the life of the asset;
  - Steam Turbine Stop Valve inspection required for safety;
  - Clean and repair winding end turns and electrical testing for Beaver Steam Turbine Unit 7 to extend the useful life and reduce risk of insulation failures.
- PW1:
  - Combustion turbine end winding update and support structure improvement to mitigate excessive vibration;
  - Steam Turbine Overhaul Components.
- PW2:
  - Catalyst door insulation replacement needed due to wear from frequent usage.

Wind Plants

Q. Please describe the major drivers to PGE's wind generation non-labor O&M.

A. The $1.8 million increase to wind generation expense is being driven by two factors. First, PGE expects approximately $3.3 million in additional turbine costs due to aging assets, primarily at the Biglow and Tucannon wind facilities. Under our LTSAs, PGE will incur routine cost escalations to maintain these important assets. As our turbines get older and material prices increase for repairs, maintenance parts also increase in price under the LTSA agreements. Such maintenance investments are necessary to maintain high wind plant availability and to help meet decarbonization targets. Second, PGE forecasts an approximate $0.2 million increase to the availability damages/bonuses payment for the Biglow and Tucannon wind facilities. Under PGE's LTSA agreements with Vestas, these payments are a percentage of the parts and services, which have an annual escalation specified in the agreement.

Hydro Plants

Q. PGE forecasts an overall decrease to hydro plant non-labor O&M. What is driving the decrease?

A. The $1.4 million decrease to non-labor hydro plant expenses is being primarily driven by two factors. First, the Westside Hydro Plant Control Simulator project was cancelled, resulting in a 2024 forecasted O&M reduction of approximately $0.3 million. Second, overall maintenance costs are forecast to be lower than 2022, as activities return to normal following additional maintenance resulting from the 2020 Labor Day Wildfire Emergency.

2. Labor O&M Expenses

Q. Is generation labor O&M forecast to increase from 2022 to 2024?

A. No. If excluding IT expenses, generation labor O&M expenses are forecast to decrease by approximately $0.5 million (or 0.7% annualized) in 2024 compared to 2022 actuals, as shown in Table 3 below. This is in contrast to base labor escalation forecast at approximately four percent annually. The savings in labor costs for generation O&M is due primarily to both overtime and straight-time labor cost decreases at Beaver, PW1, and PW2. In short, PGE's westside thermal plants experienced an increased level of labor-related plant maintenance expense for 2022. However, for 2024, PGE has budgeted for a level of maintenance at these plants below 2022 actual amounts and more consistent with historical spending patterns. See PGE Exhibit 500 for a discussion on overall 2024 labor trends.

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

Operating Area	2022 Actuals	2024 Forecast	Delta 2022 vs. 2024	Annual % Change
Gas-Fired Plants	$16.9	$15.5	($1.4)	-4.2%
Hydro Plants	$6.7	$7.0	$0.2	1.8%
Wind Plants	$1.4	$1.7	$0.3	11.0%
General and Miscellaneous	$14.0	$13.8	($0.1)	-0.5%
Environmental	$2.9	$3.3	$0.4	7.1%
Sub-Total	**$41.8**	**$41.3**	**($0.5)**	**-0.7%**
IT Expenses	$5.1	$6.2	$1.1	10.0%
Total	**$47.0**	**$47.5**	**$0.5**	**0.6%**

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

IV. 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 impeding stable prices. To avoid these problems, Commission Order No. 95-1216 (Docket No. UE 93) approved an accrual and balancing account treatment for major maintenance costs.

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 the swings in major maintenance costs.

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

A. Major maintenance events occur based upon maintenance intervals that are generally dependent upon a facility's capacity factor (hours run / hours in period) or established under PGE's LTSAs.[5] Additionally, in Docket No. UE 394 (2022 GRC), PGE added an MMA for the Kelso-Beaver (KB) Pipeline as a one-time mechanism to smooth out over five years, the

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

maintenance costs associated with regulatory driven major maintenance activity that took place in 2022. Listed below are examples of gas plants' 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.

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 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. Please summarize the MMAs PGE included in the 2024 test year plant O&M costs.

A. For the 2024 test year, PGE will continue to have 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 now recovers these costs through Schedule 146.

Q. What is the total MMA amount included in the 2024 test year plant O&M costs?

A. The total MMA amount included in the 2024 test year is approximately $17.2 million, inclusive of amounts recorded under Account 456, Other Revenues. As noted previously in Table 2, the 2024 test year MMA expense charged to generation O&M is forecasted to increase by approximately $5.3 million over 2022 actual major maintenance expenses. However, as reflected in PGE Exhibit 804, 2024 forecasted MMA expense, inclusive of MMA amounts recorded in Account 456, Other Revenues, is approximately $1.5 million higher than the UE 394 annualized MMA collection amount currently in base rates.[6]

[6] *See* Exhibit 804, cell G8.

V. Faraday Resiliency and Repowering Project

A. Intro to Faraday

Q. Please provide a high-level description of the scope of the Faraday Resiliency and Repowering Project.

A. The Faraday Resiliency and Repowering Project replaced the original 16 MW Faraday Units 1 through 5 (the 1907 Faraday Powerhouse) with a new powerhouse containing two modern, high-efficiency turbines, each with 9.4 MW of capacity, referred to as Units 7 and 8 (Faraday Units 7-8). Faraday Units 7-8 were placed in service in January 2023 and are currently serving customers. The new Faraday Units 7-8 powerhouse is a reinforced concrete structure with enhanced flood protection systems, and the new turbines will increase plant reliability and efficiency. Faraday Unit 6 is still in good condition and no upgrade was necessary.

Q. Please summarize why the Faraday Resiliency and Repowering Project was necessary?

A. The 1907 Faraday Powerhouse was an un-reinforced masonry building, which was seismically unfit, subject to flooding, and thus requiring significant investment to continue safe and reliable operation. The facility and plant equipment had outlived its original design life, did not meet current structural code, and required increasing O&M costs. Additionally, PGE is required under federal law, FERC regulations, and its License, to repair, restore and mitigate safety risks, including those imposed by earthquakes. The Faraday Resiliency and Repowering Project mitigates seismic and safety risks and provides customers with a new, non-emitting modern plant (Faraday Units 7-8) that will optimize the generation potential at Faraday for the remaining FERC license period (i.e., until 2055) and likely beyond.

Q. What is the strategic importance of Faraday?

A. Faraday has been an important component of PGE's generation portfolio since 1907, providing sustainable, clean energy and capacity to PGE customers and communities. It also provides resource diversity in PGE's overall resource portfolio, critical to meeting our carbon-free energy requirements at a time when PGE's operations are impacted by regional resource adequacy shortages, ambitious decarbonization policies, and an increasingly urgent need to address climate change. We provide more detail on the strategic importance of Faraday in Section V.F.

Q. Please summarize the challenges identified in the years prior to PGE making the decision to pursue the Faraday Resiliency and Repowering Project.

A. In 2010, PGE was issued its required Federal Energy Regulatory Commission (FERC) license covering the operation of all hydroelectric facilities, including the Faraday Powerhouse, on the Clackamas River. In the years following the license renewal, PGE commissioned seismic evaluations for most "West Side Hydro"[7] projects (i.e., Faraday, River Mill, Oak Grove, and T.J. Sullivan), and performed additional inspections. Pursuant to these actions, PGE identified the following high-level concerns related to the 1907 Faraday Powerhouse:

- The 1907 Faraday Powerhouse lacked seismic reinforcement to ensure structural integrity during a seismic event and was at risk of catastrophic failure during such conditions.
- The 1907 Faraday Powerhouse had experienced extensive flooding over time and had very limited protection from future flooding events.

[7] "West Side Hydro" is a company term denoting all company hydroelectric projects on the west side of the Cascade Mountains. It includes two FERC-licensed hydroelectric projects, the Clackamas Hydroelectric Project, No. P-02195, and Willamette Falls Hydroelectric, No. P-02233.

- Plant equipment had exceeded its useful life, and the age of plant equipment was expected to create operational challenges in predicting the type and duration of unplanned outages.

Q. Did PGE discuss and provide evidence regarding the need to repower the 1907 Faraday Powerhouse in prior rate cases?

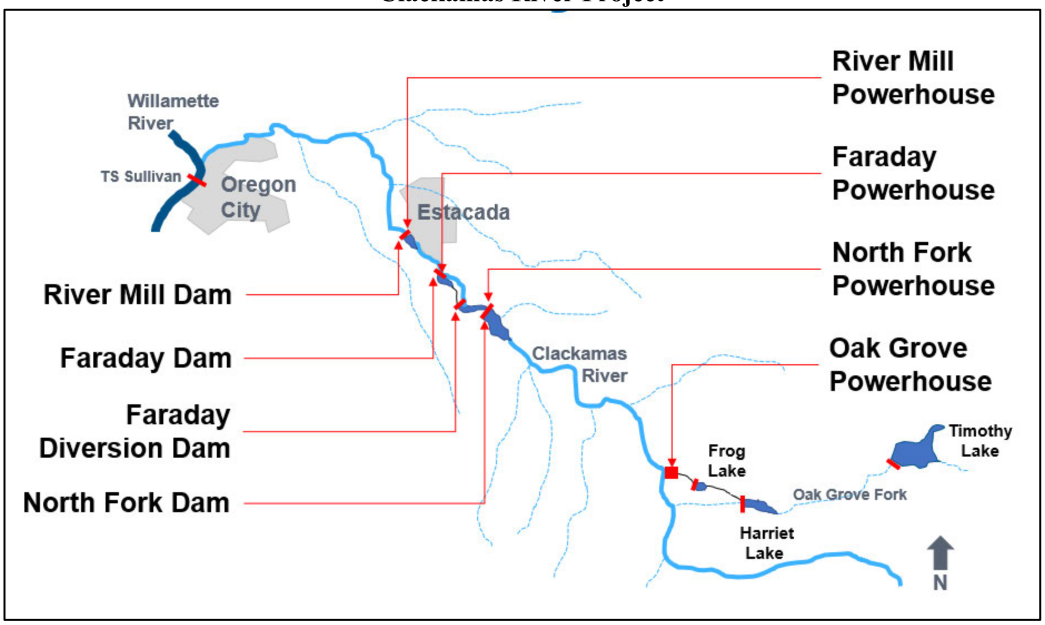
A. Yes. PGE included the Faraday Resiliency and Repowering Project costs in its 2022 GRC filing in Docket No. UE 394 based on Faraday's then-projected in-service date in the first half of 2022. In that docket, PGE presented the rationale behind the decision to pursue the Faraday project and responded to parties' arguments regarding the prudence of this decision. However, because the construction schedule was delayed, PGE and parties agreed to remove the Faraday-related capital costs from the revenue requirement for the May 9, 2022, effective date of the 2022 GRC. Under the terms of the agreement in UE 394, PGE was allowed to propose, and parties were free to oppose, any request for a tariff rider in the UE 394 case or a single-issue ratemaking proceeding. Subsequently, the Commission denied PGE's request for a tariff rider or a single-issue ratemaking proceeding. Faraday Units 7 and 8 were placed in service at the end of January 2023, and therefore, we are including Faraday-related costs in the 2024 GRC rate base.

B. Background on Faraday Hydro Facility

Q. Please describe the original Faraday Hydro Facility.

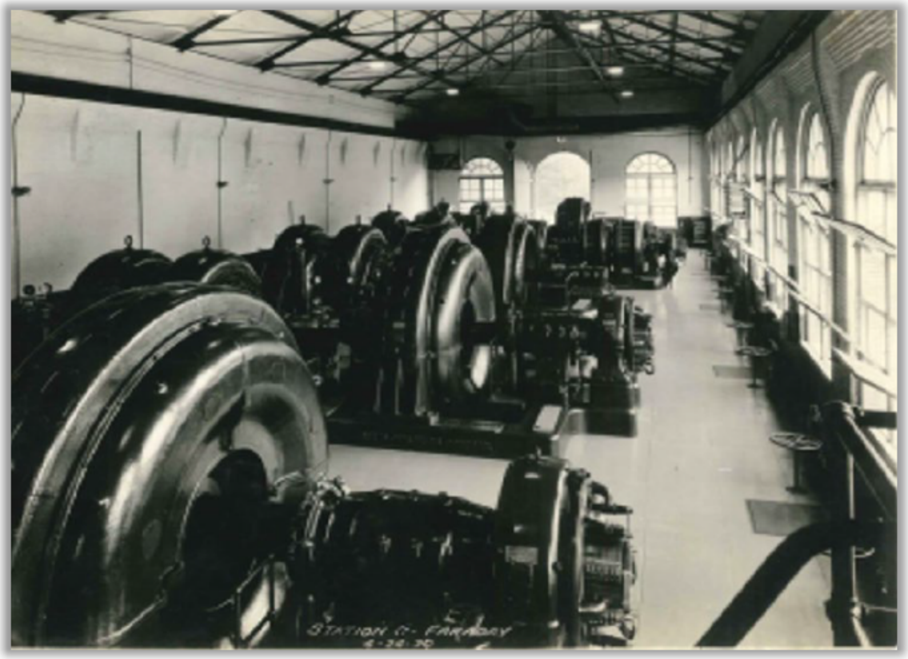
A. As originally designed, the Faraday Powerhouse included five generating units (Units 1-5) with a total 16 MW of capacity. The initial three units were placed in service in 1907, and the additional two units were placed in service in 1910. Faraday is one of PGE's multiple hydro facilities located on the Clackamas and Willamette Rivers that make up the West Side Hydro facilities. West Side Hydro includes eight powerhouses and 28 turbine generators totaling a FERC-authorized installed capacity of 178 MW. West Side Hydro includes all hydroelectric projects on the Willamette and Clackamas Rivers. Within West Side Hydro, the Clackamas River Project includes all facilities on the Clackamas River, including Oak Grove, North Fork, Faraday, and River Mill. Figure 1 below identifies where the hydro projects are located on the Clackamas River.

Figure 1
Clackamas River Project



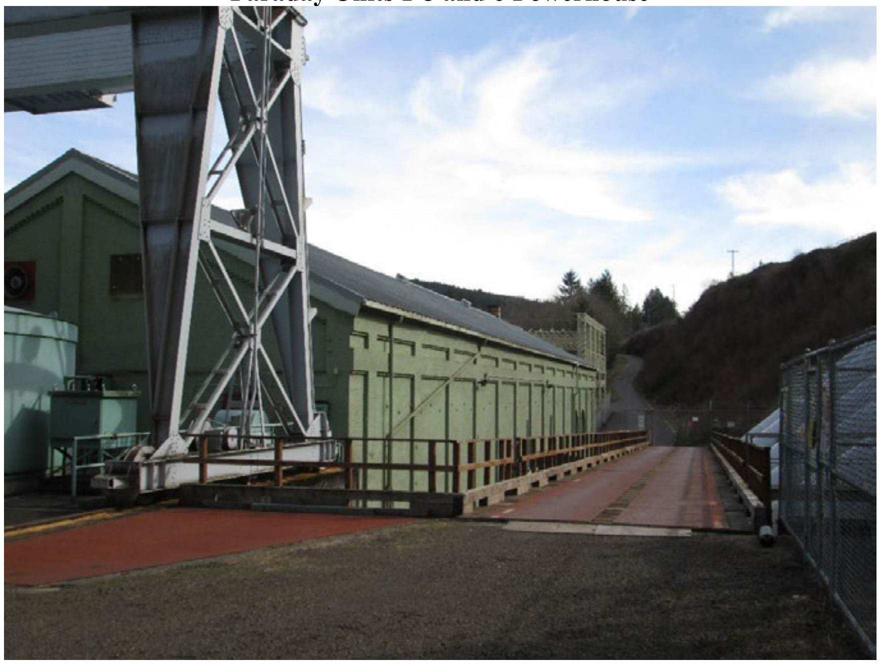
When it was originally built, Faraday consisted of a gravity dam, intake, tunnel, canal, forebay with spillway and unit intakes, penstocks, and a powerhouse containing five turbine units along with supporting mechanical and electrical systems. The turbine Units 1-5 were horizontal double-runner Francis turbines. Figure 2 below provides a visual of the 1907 Faraday Powerhouse interior and the Francis turbines.

Figure 2
1907 Faraday Powerhouse Interior



A new intake, penstock, and powerhouse with one vertical Francis turbine (Unit 6) was added to Faraday in 1958. Figure 3 shows the Faraday Powerhouse in the 1950s with the Unit 6 addition in the foreground and the original 1907 building in the background.

Figure 3
Faraday Units 1-5 and 6 Powerhouse



Q. Please describe Faraday's operation after Unit 6 was added in the 1950s.

A. Over the years, PGE operated and maintained the Faraday hydro facility, providing customers with safe, reliable, and clean energy generation. For over a century, the Faraday hydro project performed well with no major operational or reliability issues, except for impacts from the 1964 and 1996 historic flood events.[8] These flood events required extensive maintenance and repair work. However, as we will describe in more detail in the following sections, after the 2010 FERC Clackamas License renewal, we discovered crucial structural issues due to the old age of the 1907 Faraday Powerhouse structure and generating equipment that had far exceeded their useful life and were no longer seismically fit or mechanically reliable. These issues were expected to impact plant safety and reliability and required remediation actions, leading to the Faraday Resiliency and Repowering project.

[8] The 1964 and 1996 floods were 1-in-250 years extreme flow events.

C. Faraday Resiliency Review

Q. What are the FERC licensing requirements to operate the hydroelectric facilities on the Clackamas River?

A. To operate all hydroelectric generating plants on the Clackamas River, including Faraday, PGE must maintain and comply with FERC licensing requirements under sections 4(e) and 15 of the Federal Power Act.[9] In August 2004, PGE filed an application with FERC for a new license authorizing the continued operation and maintenance of the Clackamas River Hydroelectric Project No. 2195, referred to as the "Clackamas River Project." The Clackamas River Project covers the 162 MW provided by four hydroelectric plants[10] and applies to over 3,596 acres of land; 2,423 of which are federal lands within the Mt. Hood National Forest.[11] The Clackamas River Project FERC license allows PGE to continue operation and maintenance of all its hydroelectric projects on the Clackamas River.[12]

Under the terms of the FERC license, PGE must safely and reliably manage the generating units. PGE must also comply with all applicable federal regulations, including fish and aquatic species protection, maintaining cultural resources and recreation sites, and protecting terrestrial boundaries. As mentioned above, in 2010 FERC granted a renewal of PGE's license for operating our Clackamas River Project for an additional 45 years.[13]

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[9] 16 U.S.C. §§ 797(e) and 808.
[10] The four developments covered by the Clackamas River Project FERC license include North Fork, Faraday, River Mill, and Oak Grove.
[11] *See Portland General Electric Company,* 133 FERC ¶ 62,281, (2010) at ¶ 11 (Order Issuing New License); "The Clackamas River provides significant recreational opportunities...supports regionally important anadromous fish population…also provides drinking water for approximately 200,000 people."
[12] Id. PGE filed an application for the new license on August 26, 2004, with the order granting the new license issued on December 21, 2010.
[13] *See* 134 FERC ¶ 61,206, Order on Rehearing Issued on March 17, 2011. (The December 21, 2010 Order issuing a new license for the Clackamas Project No. 2195 revised for Ordering Paragraph (A) to read: This license is issued to Portland General Electric Company (licensee), for a period of 45 years, effective the first day of the month in which this order is issued, to operate and maintain the Clackamas River Hydroelectric Project).

During the FERC licensing process, FERC staff reviewed PGE's plans and its ability to maintain the Clackamas River Project in an efficient and reliable manner. The review by FERC staff indicated that PGE performs a comprehensive program of inspections and maintenance for all major Clackamas River Project components, including regular inspections and regular maintenance and repairs of the Clackamas Project turbine generator units to ensure they continue to operate in an optimal manner to minimize effects on energy production.[14]

Q. What actions did PGE undertake after FERC renewed the license to operate the Clackamas River Project?

A. In the years following the 2010 FERC license renewal, to support the ongoing safe and reliable operation of the hydro facilities on the Clackamas River, PGE launched a comprehensive review of all the Clackamas River Project facilities. As part of the review, all portions of the Clackamas River Project were inspected and evaluated for resiliency and reliability. While some Clackamas River Project facilities required repair work and upgrades post evaluation, only the 1907 Faraday Powerhouse was deemed structurally unfit and in critical need of major structural upgrades.

Q. Please detail the findings from the Faraday resiliency review.

A. As part of the resiliency review, PGE hired an outside engineering consulting firm to perform a seismic evaluation of the Faraday Powerhouse structure applying the American Society of Civil Engineers' (ASCE) Seismic Evaluation of Existing Buildings standards.[15] The expert evaluation report, delivered to PGE in April 2014, found that the 1907 Faraday Powerhouse,

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[14] *See Portland General Electric Company*, 133 FERC ¶ 62,281, (2018) at ¶ 132; "Staff's review indicates that PGE's comprehensive program of inspections and maintenance for all major project components includes: regular inspections of the project turbine generator units to ensure they continue to perform in an optimal manner, regular maintenance to minimize effects on energy production. …"

[15] Exhibit 805 provides the seismic evaluation report.

in addition to having other non-structural issues, was not seismically fit. The engineering expert concluded that the 1907 Faraday Powerhouse would likely either partially or totally collapse during a moderate to major seismic event because it was constructed of unreinforced masonry, one of the most hazardous forms of construction when subjected to ground motions. Therefore, the 1907 Faraday Powerhouse structure was deemed "a hazardous structure when considering its lack of reliable resistance to earthquake ground motions."[16]

Q. What was the report recommendation?

A. The primary and most important recommendation was for PGE to address the seismic risk related to the 1907 Faraday Powerhouse. The expert recommendation identified the need for either major structural rehabilitation from the operating floor to the roof or, alternatively, that PGE demolish and replace this structure with a prestressed, precast, reinforced concrete or prefabricated steel structure designed and built to modern standards.

D. PGE's Decision to Pursue Repowering the 1907 Faraday Powerhouse

Q. Aside from structural integrity issues, were there other issues concerning the 1907 Faraday Powerhouse?

A. Yes. The 1907 Faraday Powerhouse was at increased risk of non-operation and flooding during high river flow events because of the low flood wall which exposed the generator deck.[17] A high-flow event is typically forecasted to happen once every two to five years. High-flow levels impeded the crew's access to the 1907 Faraday Powerhouse. Additionally, due to the risk of contaminants being released into the river during a flood, whenever a high-flow event was predicted, operators would stop plant operations and

[16] *See* Exhibit 805, Section III. Recommendations, paragraph A, pg. 4.
[17] The 1907 Faraday Powerhouse generator deck is at 402 feet elevation.

preemptively remove oil in anticipation of flooding to avoid environmental, permitting, and license compliance issues. The high risk of flooding, especially given the increased frequency of climate change-driven significant weather events in recent years, created uncertainties regarding the duration of future outages, as well as the likelihood for increased costs for restoration, repair, or replacement of structures and equipment.

Q. How did the age of the 1907 Faraday Powerhouse equipment impact reliability?

A. Numerous pieces of plant equipment had exceeded their useful lives, which was expected to impact plant availability and reliability, and require increased O&M costs. For example, the most important plant equipment, the horizontal Francis turbines, were the original 1907 vintage equipment. Industry standard life for these types of turbines was approximately 50 years. The age of the plant equipment meant that PGE had limited access to skilled labor, parts, and materials, which in turn made it challenging to predict the type and duration of unplanned outages. If parts were needed for a 100+ year old turbine, the only option would be custom manufacturing and a special order, which could be time-consuming and expensive. Additionally, most modern hydro turbines are configured in the vertical style. Consequently, if the original horizontal hydro turbines failed and unexpectedly needed to be replaced, it would require major structural modifications to the penstocks, draft tubes, and powerhouse, and associated costs.

Q. What actions did PGE undertake after identifying all the issues described above?

A. The issues identified at the 1907 Faraday Powerhouse required PGE to analyze and determine the most prudent course of action that would support plant operational safety, reliability, and conformance with applicable seismic standards. While purely economic factors were considered in the review of available options, PGE's analysis also prioritized maintaining

PGE's ability to safely and reliably operate Faraday while continuing to provide clean and sustainable energy benefits to customers. To do this, PGE needed to address the seismic and flooding concerns and the reliability of the plant equipment so that PGE could continue to operate Faraday under the Federal Power Act, FERC regulations, and conditions of our FERC license for the Clackamas River Project.

Q. What options did PGE consider regarding the 1907 Faraday Powerhouse operations?

A. PGE considered and analyzed the following options:

1. Do nothing beyond routine maintenance for the existing powerhouse and original turbine-generators.
2. Retrofit the existing powerhouse structure and maintain original turbine-generators.
3. Replace the powerhouse structure and maintain original turbine-generators.
4. Replace the powerhouse structure and install new turbine-generators.

Q. Please discuss the "do nothing" option.

A. This option would have maintained the existing 1907 Faraday Powerhouse with no seismic rehabilitation or improvements and the original, 1907 vintage turbine-generators. This option was not considered viable or prudent because it would not remediate any of the safety issues identified at Faraday: i.e., the structural issues discovered through the 2014 seismic evaluation, the flood risk, and the deficiencies and old age of the existing turbine-generator equipment.

Q. Please discuss the option to retrofit the existing powerhouse while maintaining the original turbine-generators (Option 2).

A. This option would have installed seismic enhancements and other improvements to the existing unreinforced masonry building housing the generator units. This option was not considered viable or prudent because it would incur significant costs without mitigating the flood risk or addressing the deficiencies and age of the existing turbine-generator equipment.

Q. Please discuss the option to replace the existing powerhouse while maintaining the original turbine-generators (Option 3).

A. Option 3 would have involved undertaking multiple major capital upgrades that were required to ensure safe and reliable operations at the 1907 Faraday Powerhouse. This option would have also involved demolishing and replacing the existing unreinforced masonry powerhouse with a steel frame, cast-in-place walled powerhouse. However, Option 3 would not have replaced the 1907 turbine-generators and therefore would have not addressed the deficiencies and age of the existing turbine-generator equipment. As previously described, the old age of the turbine equipment was creating operational risks because of limited access to skilled craft workers, parts, and materials to maintain this type of equipment. Additionally, if the 1907 turbine-generators failed and unexpectedly needed to be replaced, it would require major structural modifications.

Q. Were there conditions in the Clackamas River Project FERC license that applied to the maintenance of hydroelectric projects, including Faraday?

A. Yes. As previously described, the 2010 FERC license covers all of PGE's hydroelectric facilities on the Clackamas River. The 2010 FERC license provides that "if the Licensee shall cause or suffer essential project property to be removed or destroyed or to become unfit for use, without adequate replacement, […], the Commission will deem it to be the intent of the Licensee to surrender the license." Therefore, in the scenario where PGE continued operating Faraday without seismic upgrades, a catastrophic failure at Faraday could have put at risk the FERC license required to operate all the Clackamas River hydroelectric facilities and potentially could have required PGE to remove any or all structures, equipment, and power lines within the project boundary.[18]

Q. Were there any regulatory obligations that necessitated the replacement or rehabilitation of the 1907 Faraday Powerhouse?

A. Yes. Under the Federal Power Act, FERC regulations and the conditions of our license for the Clackamas River Project, PGE is required to keep our hydroelectric projects in repaired and adequate working order for the entire 45-year license term and, if needed, to "make all necessary renewals and replacements."[19] Furthermore, PGE is required to retrofit any hydroelectric facility to maintain the safety of the water power projects. Earthquakes are specifically identified in federal regulations as conditions affecting the safety of project or project works.[20]

Additionally, the Clackamas River supports endangered salmon and trout and provides drinking water for approximately 200,000 people. A collapse during a seismic event risked releasing into the river hazardous materials such as lead-based paints and asbestos, both present in the 1907 Faraday Powerhouse, jeopardizing wildlife and drinking water. Therefore, it was necessary for PGE to take action with respect to rehabilitating or replacing the 1907 Faraday Powerhouse.

Q. Please provide additional detail regarding Option 4, which was eventually selected.

A. This option would essentially deliver a new hydro plant powerhouse that meets applicable structural seismic standards and is protected against flooding risks, allowing PGE to comply

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[18] *See* Order Issuing New License 133 FERC ¶ 62,281(2010) at pg. 49; Director Order ¶ (K) directing license to be subject to articles, entitled "Terms and Conditions of License for Constructed Major Project Affecting Navigable Waters and Lands of the United States."
[19] 16 U.S.C. § 803 (2010) Conditions of license generally.
[20] 18 CFR Part 12.3(4)(xii), Safety of Water Power Projects and Project Works.

with the Federal Power Act, FERC regulation, and our license. Additionally, the option would replace the 16 MW, 1907 turbine-generators, which had long exceeded their useful life, with new, 18.8 MW turbine-generators. The new plant with a 40-plus year design life is expected to optimize generation potential for the remaining FERC license period through 2055 as well as any future license reauthorization period. Therefore, PGE considered Option 4 to be the prudent decision and provide the best outcome for the 1907 Faraday Powerhouse operations and for continuing to operate all hydroelectric projects on the Clackamas River in compliance with statutory and FERC license upkeep requirements.

Q. Did PGE perform an economic analysis before choosing Option 4?

A. Yes. PGE performed a Net Present Value (NPV) analysis in 2016 to compare Option 3 with the option to repower. As we will describe in more detail below, PGE hired an external consulting firm to determine a probable cost estimate with information known at that time and perform analysis regarding the various repowering options. Based on the cost estimate provided by the consulting firm, the economic analysis showed that the repowering scenario Option 4 had a greater NPV than Option 3.[21]

Q. Why was decommissioning the 1907 Faraday Powerhouse not a viable or reasonable option at that time?

A. Decommissioning the 1907 Faraday Powerhouse would not have been a viable or reasonable option at that time because it would have resulted in: 1) a reduction to PGE's resource portfolio when PGE was already resource deficient; 2) forgoing the annual energy benefit Faraday provided and was expected continue to provide to customers for another

[21] Exhibit 808 provides the economic analysis. See tab "Assump", cell O24 for the delta between the two scenarios NPVs.

approximately 40 years under the existing FERC license; 3) forgoing the eligibility to earn Production Tax Credits associated with incremental energy from repowering; 4) the need to retrofit the access way to Faraday Unit 6 and protect the remaining unit from future flooding; and 5) significant efforts required to decommission the 1907 Faraday Powerhouse. Additionally, while not necessarily a major issue at that time, simply decommissioning the plant would have only exacerbated the regional energy shortfalls observed in the recent years and reduced PGE's renewable resources portfolio at a time when we are committed to meet aggressive House Bill (HB) 2021 decarbonization directives. Therefore, because of the significant benefits Faraday provides—and will continue to provide for decades to come—PGE did not and still does not consider the decommissioning of Faraday to have been a beneficial option for customers.

The value Faraday provides as a hydro facility compared to not having it in operation is demonstrated in the decision to grant the Clackamas River Project license where FERC stated:

> (1) issuance of a new license will serve to maintain a beneficial, dependable, and inexpensive source of electric energy; (2) the required environmental measures will protect and enhance fish and wildlife resources, water quality, recreational resources, and historic properties; and (3) the 173 MW of electric energy generated from a renewable resource may offset the use of fossil-fueled, steam-electric generating plants, thereby conserving nonrenewable resources and reducing atmospheric pollution.[22]

Q. Please describe the type of work that would have been required to decommission the 1907 Faraday Powerhouse.

A. While we will not list every step and requirement in detail, the critical aspects of decommissioning the 1907 Faraday Powerhouse would have involved complex and lengthy

[22] *See* Order Issuing New License, 133 FERC ¶ 62,281 at ¶ 147.

regulatory processes related to FERC licensing to receive all necessary approvals and amendments to the license to operate the Clackamas River Hydro Project and identification of remediation steps needed to return unused areas to a natural condition. Additionally, we would have needed to perform much of the same construction work involved in the repowering project. Specifically, decommissioning the 1907 Faraday Powerhouse would require: the construction of a cofferdam; demolition of the 1907 Faraday Powerhouse; removal of all the penstocks for Units 1-5; dewatering the construction area; retrofitting the Faraday dam to block the penstock penetrations in the dam; and, retrofitting Unit 6 to protect against flood events and to add a new access way. As mentioned above, decommissioning would involve significant effort and customers would have foregone the project's clean hydroelectric energy benefits for the remaining years under the FERC license to operate the Clackamas River Project.

E. Faraday Resiliency and Repowering Project Development

1. Project Planning Phase

Q. You mention that PGE engaged an external consultant to analyze the best repowering options. Please provide additional detail.

A. Yes. In January 2016, given the complexity of a hydro repowering project and to determine preliminary cost estimates and the most beneficial repowering option for customers, PGE engaged Kleinschmidt to perform a comprehensive powerhouse upgrade study on Faraday. PGE chose Kleinschmidt because it is a highly reputable company with more than 50 years of experience in hydropower facilities, including modernization, rehabilitations, and the building of new facilities.

Q. Please provide a brief description of the purpose of the Kleinschmidt study.

A. PGE commissioned the study to assist in PGE's evaluation of whether a comprehensive upgrade of the facility, including the installation of new turbine-generators, would be a more economic investment than Option 3, previously described. The study was finalized in April 2016.

Q. Please describe the Kleinschmidt cost estimate.

A. Kleinschmidt developed a breakdown of project components to create an opinion of probable construction costs based on the best information known at that time, consistent with a Class 4 level, as defined by the AACE[23] International classification system for the hydropower industry. A Class 4 level is defined as a cost estimate at a project maturity level of 1 to 15%. Figure 4 below provides the AACE ranges of accuracy for construction projects in the hydropower industry. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Was the Kleinschmidt estimate intended to be the same as an actual proposal for the total project cost by a contractor within a Request for Proposal (RFP) process?

A. No. The Kleinschmidt estimate was intended to improve PGE's understanding of a possible Faraday project rebuild without performing a deeper penetration of the Faraday structure. It was not intended to be actual project cost calculations. For example, the Kleinschmidt study

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[23] AACE International is the Association for the Advancement of Cost Engineering.
[24] In 2016 dollars.

compared vertical and horizontal turbines and identified the benefits of vertical turbines in terms of cost, greater energy output, and improvement in fish survival.[25]

Figure 4
AACE Cost Estimate Classification System

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

Q. Did you expect variances between actual project costs and the estimate provided by Kleinschmidt in April 2016?

A. Yes. As previously described, the original project cost estimate was a Class 4 level estimate created during the planning phase of the design work, at a project maturity of less than 15%. A Class 4 level cost estimate can range from -30% to +50% cost variance, as depicted in Figure 4, above.[26] PGE used the estimate to assist with the decision to move forward with the Faraday Resiliency and Repowering Project. However, due to the high complexity, uniqueness, and uncertainties inherent in the repowering of a 100+ year-old hydro facility, PGE understood that overall costs would be evaluated at 90% project design to determine whether to re-evaluate budget and scope after receiving actual construction bids.

[25] *See* Exhibit 806-Powerhouse Upgrade Study, sections 7.0-8.0.
[26] The AACE cost classification system is also provided in the Powerhouse Upgrade study, submitted as PGE Exhibit 806.

Q. When did PGE begin design efforts for the Faraday Resiliency and Repowering Project?

A. After making the decision to repower pursuant to the internal analysis of options, PGE issued an RFP in 2016 to select an engineering company for the new Faraday Units 7 and 8 (replacing the 1907 Faraday Powerhouse) powerhouse design and for selecting the hydro turbines that would replace the old, 1907 original turbines. Based on the RFP, PGE hired the highest ranked candidate in December 2016 and began design efforts for the repowering project. In March 2018, the engineering company delivered a Turbine Selection Study,[27] recommending the installation of Kaplan vertical hydro turbines. PGE ordered the hydro turbines following this report and before the solicitation process for hiring a general construction contractor to mitigate against long lead time for this type of equipment.

<u>2. Project Execution Phase</u>

<u>*General Contractor Selection and Construction Project Complexities*</u>

Q. What was the selection process for the original general construction contractor?

A. To determine the best option for building the Faraday Resiliency and Repowering Project, we issued an RFP beginning the solicitation process in September 2018. At that time, the project was at 90% design and the RFP was intended to allow bidder-review of the design for potential constructability issues. The RFP considered pricing, technical, financial risk, and safety ranking criteria to evaluate potential candidates. PGE hired the highest-ranking candidate. Additionally, the original construction contractor hired pursuant to the RFP was the most experienced bidder for in-water construction work and had the highest overall technical score. The RFP criteria and candidate ranking are provided in Exhibit 809.

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[27] *See* PGE Exhibit 807.

Q. When did PGE hire the general construction contractor?

A. In December 2018, PGE and the RFP highest ranking candidate ("General Contractor") executed a construction contract with a clause that the original contract will be amended shortly to include a project schedule and estimate of costs. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Including the construction contract cost and turbines, the total project cost estimate and budget was $84.0 million[28] when the project started.

Q. Why did the project cost change between the initial 2016 estimate and 2019?

A. As previously mentioned, the initial 2016 estimate was based on a project maturity level of 1% to 15%. At that project maturity level, it is expected that estimated project costs will change. The updated budget cost was based on actual construction bids with the revision being due to higher than initially estimated construction costs related to the cofferdam construction and dewatering, reinforced concrete design, and material and labor pricing.

Q. You mention that the construction bids and subsequent total project cost were based on a 90% design. What is the expected cost accuracy level for a 90% project design?

A. At 90% project design, a cost estimate would be consistent with a Class 1 probable cost estimate, as defined by AACE International classification system for the hydropower industry. Under normal circumstances, a Class 1 probable cost estimate is expected to vary up to +15%, as reflected in Figure 4. Consequently, a theoretical 15% project cost increase from the $84.0

[28] Expected costs incurred, not including AFUDC and loadings.

million budget (up to approximately $96.6 million),[29] would have been within accepted industry standards. However, as we will describe in this testimony, the Faraday Resiliency and Repowering Project was impacted by numerous factors that were outside of PGE's control, pushing total project costs beyond the typical cost variation.

Q. Did you perform additional economic analysis using the updated $84.0 million project cost and budget estimate?

A. Yes, we performed additional analysis to review the economics of the Faraday Resiliency and Repowering Project in April 2019, after we received actual bids and updated the estimated project cost and budget. The updated analysis focused on the economics of the repowering project and did not evaluate Option 3. We were no longer considering Option 3 because it would not have replaced the original 100+ years old turbines that had exceeded their useful life. As previously described, an eventual failure of the original turbines would have created major operational complications and would have required structural modifications and associated costs to the penstocks, draft tubes, and powerhouse. Such event and the costs for replacing the original turbines were not accounted for in the economic analysis. Therefore, although the economic analysis with the updated project cost reflected a net cost of $8.4 million, repowering the 1907 Faraday Powerhouse continued to be the best option because it would address the major structural deficiencies discovered through the 2014 seismic study, upgrade the hydro turbines, and ensure reliable and safe operations at Faraday.

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[29] The amounts are reported in 2019 dollars. If adjusted for inflation and reported in 2023 dollars, the project budget at 90% design would be approximately $97.5 million and would be within accepted industry norms if it would increase by 15% to approximately $112.2 million.

Q. When did the project construction begin?

A. The on-site mobilization began in March 2019 and the demolition of the 1907 Faraday Powerhouse began in July 2019.

Q. Please detail the construction work performed as part of the Faraday Resiliency and Repowering Project.

A. Following the design work completed in the planning phase, the Faraday Resiliency and Repowering Project construction work included the following:

1. Construction of a cofferdam to divert the Clackamas River and de-water the construction site;
2. Demolition and removal of the 1907 Faraday Powerhouse including all five generating units and auxiliaries, all balance of plant equipment, and all other equipment or items in the powerhouse;
3. Demolition and removal of five existing penstocks;
4. Demolition of other structures and buildings;
5. Construction of a new powerhouse structure and bridge crane to install, house, operate and maintain the electro-mechanical equipment;
6. Installation, testing and commissioning of balance of plant equipment;
7. Construction of micropiles and slope stabilization measures to support the new penstocks;
8. Fabrication, installation and testing of new penstocks;
9. Construction of intake structure modifications, including new trash racks and headgate actuators;
10. Construction of a new flood wall; and

11. Installation of a new backup generator.

Q. Did PGE submit Faraday Resiliency and Repowering Project construction plans and project scope materials for FERC review before starting the construction project?

A. Yes. To ensure compliance with federal regulation, PGE initiated a FERC license amendment process on April 19, 2017, and provided details regarding the action plan for addressing the reliability and safety risks associated with the 1907 Faraday Powerhouse. The license amendment application was prepared using a three-stage consultation process with the appropriate agencies and stakeholders, as required by FERC regulation. Following stakeholder consultations, PGE submitted the application to amend the FERC license on March 16, 2018. Pursuant to a thorough review of PGE's application, FERC Staff's recommendation was that PGE pursue its proposed action plan: i.e., rebuilding and repowering the 1907 Faraday Powerhouse. Exhibit 810 provides FERC's Environmental Assessment for Non-Capacity Amendment to License, including the FERC Staff recommendation (see Section 4.0).

In addition, all construction design plans were submitted to FERC's Division of Dam Safety and Inspections Portland Regional Engineer Office prior to construction. PGE submitted our Quality Control Inspection Plan to demonstrate how we would ensure quality of the project work since we could not begin construction until the Portland Regional Office reviewed and commented on the plans and specifications and authorized the start of construction.

Q. Please describe some of the plans and specifications that FERC's Portland Regional Office evaluated.

A. As part of the preconstruction requirements, FERC's Portland Regional Office reviewed and sometimes proposed modifications on: 1) the quality control and inspection program; 2) temporary construction emergency action plan; 3) temporary construction potential failure mode assessment; 4) soil erosion and sediment control plan; 5) engineering design drawings and specifications; 6) cofferdam construction plans; and 7) the drilling and excavation plan.

Q. Did the Faraday Resiliency and Repowering Project present unique aspects and complexities compared to other construction projects?

A. Yes. Due to intrinsic complications related to hydro projects and the numerous unforeseen events that impacted project construction, the Faraday Resiliency and Repowering Project presented several unique aspects and complexities:

1. The project involved significant in-water work. For fish protection and environmental purposes, the Oregon Department of Fish and Wildlife (ODFW) designates a window when in-water work is permitted. Specifically, in-water work is ordinarily restricted by ODFW from July 15 through August 31 for the Clackamas River.[30] PGE then had to apply for Army Corps of Engineers (ACOE) and Oregon Department of State Lands (DSL) joint permit to work within the designated in-water work period. The limited window for in-water work increased the risk and magnitude of construction schedule delays when there were unforeseen impacts to the construction project. As we will describe below, the project was further impacted by numerous unforeseen and

[30] ODFW ordinary in water work windows can be found here: https://www.dfw.state.or.us/lands/inwater/Oregon%20In-water%20Work%20Guidelines%20January%202022.pdf

extraordinary events, from the COVID-19 pandemic, to flooding, wildfires, and supply chain issues, resulting in project schedule delays and increased costs.

2. The project required diverting the Clackamas River through the construction of a cofferdam. The cofferdam allowed for de-watering the construction site and managing seasonal water flows. As described above, ACOE and DSL only permit in-water work within the ODFW designated in-water work periods unless an extension is granted. This was the only time during a given year when construction equipment could be mobilized into the Clackamas River to construct or remove the cofferdam.[31]
3. There have been significant supply-chain challenges with procurement of equipment because the production of hydropower equipment in the US has declined over the last several decades. This required PGE to procure the specialized equipment from international suppliers,[32] which in turn led to long lead times for design and procurement.
4. The Faraday Resiliency and Repowering Project work had to be performed in compliance with all applicable FERC hydro licensing regulation. Additionally, the project entailed protecting the river and surrounding area from the hazardous materials used to build the 1907 Faraday Powerhouse, including materials such as lead-based paints or asbestos.
5. The nature of the project, given the 100+ year age of the 1907 Faraday Powerhouse, involved risks associated with site issues that would not be easily identifiable prior to

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[31] To help mitigate these constraints, PGE requested and was granted permission to extend the in-water period for the following periods: 7/8/2019-7/15/2019; 9/1/2019-9/30/2019; 6/1/2020-11/30/2020; 9/1/2021-10/31/2021; 9/1/2022-11/1/2022.

[32] PGE sourced specialized equipment from Switzerland (turbine inlet valves), Brazil (generators), Canada-Ottawa (turbines), Canada-Victoria (control systems), and Mexico (switch gear).

starting the project. For example, there was more construction work than initially anticipated on the adjoining hillside that was identified after the original penstocks were demolished. The additional construction work was needed because the sub-surface geotechnical conditions and the state of the concrete supports were not as initially expected and adapting the project design required significant modifications. Also, the project entailed demolishing the 1907 Faraday Powerhouse concrete structure while ensuring that the adjacent Faraday Units 6 was not damaged.

Q. You mention that the construction project schedule experienced delays. Please summarize the reasons for these delays.

A. The Faraday Resiliency and Repowering Project construction was impacted by multiple extraordinary events that occurred during the 2020 and 2021 timeframe. It began with a flooding event in January 2020, followed by the COVID-19 pandemic, which caused construction delays associated with mobilizing and demobilizing crews for safety reasons when COVID-19 outbreaks occurred. These events were soon followed by the 2020 Labor Day wildfire, which was followed by another flooding event in early 2021, as well as the historic 2021 February ice storm emergency event. These unprecedented and catastrophic events were not foreseeable when PGE entered the original construction contract. Consequently, these events contributed to delays in the anticipated in-service date of the project, which went from the initial completion estimate of Q3 2021, to Q1 2022, to Q4 2022, and the project came online in January 2023.

Q. Please elaborate on how the extraordinary and unforeseeable events mentioned above impacted the Faraday Resiliency and Repowering Project.

A. In isolation, just one of these events would have caused delays and significant cost impacts, but the sequential and sometimes simultaneous nature in which these events occurred put unprecedented strain on the work crews and the progress of the project. It should be mentioned that given the limited period allowed for in-water work on the Clackamas River, a delay of a few weeks for certain construction project milestones could have and eventually did push the entire project back one year. Below are additional details regarding how these events impacted the Faraday Resiliency and Repowering Project:

- The construction site was flooded during high river flows in January 2020, December 2020, and January 2021, causing delays in the project schedule.
- The Labor Day 2020 wildfire forced a full site evacuation and caused a power outage at the site. Without power, the hydro pumps stopped working, resulting in the flooding of the construction site and work needing to be paused for several days. The combined work cessation and necessary repair and cleanup significantly impacted the construction schedule. Also, the 100+ year old wooden access bridge was damaged by the fire, requiring the replacement of a structural column, and restricting heavy vehicle access for approximately one additional week.
- The February 2021 ice storm resulted in loss of power and unsafe work conditions causing a shutdown of the construction site.
- The COVID-19 pandemic that started during Q1 2020 and continues to cause public health concerns to this day, caused equipment vendors to delay the production of parts, which in turn introduced delays in the project schedule. The COVID-19 pandemic also

resulted in uncertainties regarding health safety, loss of qualified personnel, and caused the construction site to slow work multiple times for safety reasons due to virus outbreaks.

Figure 5 below provides image that show impacts from the September 2020 wildfire and the January 2021 flooding.

Figure 5
2020 Wildfire and January 2021 Flood

Q. How did COVID-19 cause the loss of qualified personnel?

A. Prior to the beginning of the COVID-19 pandemic, the General Contractor hired qualified personnel from out-of-state based on a planned schedule of work that allowed them to stay in Oregon, working solely on the Faraday Resiliency and Repowering project. Once the pandemic began, virus outbreaks caused issues and delays because construction crews returned to their residence state for safety and health reasons. Some out of state workers returned to the worksite once it was safe to do so, and many workers chose not to return at all, causing shortages of qualified personnel.

Q. Was the estimated project cost and budget impacted by all the factors described above?

A. Yes. The culmination of all these unparalleled extreme events and the added complexities inherent for a hydro project that involves repowering a 100+ years old plant ultimately severely impacted the project schedule and costs.

Q. Did PGE undertake certain actions to keep the project schedule on track and attempt to limit the project cost?

A. Yes. PGE closely monitored and continuously evaluated the project schedule and worked with the General Contractor to attempt to prevent further delays and cost increases. As mentioned above, much of these delays were due to extraordinary events and outside of PGE's control or ability to foresee. However, with concerns about ongoing delays and likely cost overruns, which were exacerbated by the loss of a key General Contractor employee due to health reasons, PGE and the General Contractor mutually agreed to separate and transition the work to a new general contractor, Black and Veatch Construction, Inc. or BVCI, in December 2021.

Q. How did you select BVCI?

A. Prior to executing an agreement with BVCI and transitioning the work, we considered potential candidates that would have had the capability to take over a project of such complexity and meet the expected in-service date. BVCI was hired because it had: a proven history of completing large construction projects; the ability to very quickly mobilize a qualified team to take over a hydro project of this complexity and present reliable cost estimates; the financial ability to quickly assume all sub-contracts from the original contractor; and demonstrated an ability to complete the work within the existing project schedule. Before the construction project was transitioned, the estimated in-service date was Q4 2022.

Q. Did you experience any quality or safety issues after transitioning to BVCI?

A. No. We did not experience any safety issues and no significant quality issues that would be out of the ordinary given the size and complexity of the project.

Q. Did you experience any project schedule delays after transitioning to BVCI?

A. Yes. In Q3 2022, a penstock design issue was discovered during the installation of the new penstocks, which delayed the project schedule by approximately one month. Other than that, the project proceeded as scheduled.

Q. What is the current status of the construction project?

A. The Faraday Resiliency and Repowering Project became operational consistent with design specifications previously discussed and was placed in service on January 31, 2023. Figure 6 provides an aerial view picture of the completed Faraday hydroelectric plant.

Figure 6
Faraday Hydroelectric Plant

3. Faraday Resiliency and Repowering Project Cost

Q. You describe above why the construction project suffered unforeseen delays and cost impacts. Please summarize how project costs increased as the project progressed after actual construction work began in March 2019.

A. The total project cost budget progressed as follows:

1. As previously described, the construction project budget established in 2019 was based on actual bids received for the construction work at 90% design of the project. At that time, the estimated construction cost was $62.3 million, and the total estimated project cost and budget was established at approximately $84.0 million.[33]
2. In the 2020 – 2021 timeframe, following the impacts from extraordinary and unforeseen events, and other production delays, the total estimated project cost and budget was revised to $98.2 million.[34] The revision was primarily due to an 11-month

[33] Estimated costs incurred, not including AFUDC and loadings.
[34] Estimated costs incurred, not including AFUDC and loadings.

project schedule delay caused by the shifting of the cofferdam removal from Q3 2020 to Q3 2021. The delay of the cofferdam removal was due to other construction delays that prevented the contractor from executing this work during the 2020 in-water window. As previously mentioned, in-water work is limited under ODFW regulations, meaning any construction delays have a significant impact on the overall project schedule.

3. In 2022, the total estimated project cost and budget was increased to \$147.8 million.[35] Of this total amount, \$146.1 million was placed in service when the Faraday Resiliency and Repowering Project was deemed used and useful on January 31, 2023, and approximately \$1.7 million is reflected as cost of removal within PGE's total accumulated depreciation. The additional incremental funds were necessary to cover: 1) the price for engaging the new general contractor and assuming all sub-contracts from the previous contractor, 2) the mobilization of the new general contractor to work on the site, 3) the remediation of work that was incomplete or needed revision and/or refinement, and 4) the re-sequencing of work that required re-engineering and required additional support from all of PGE's vendors, including PGE's hired engineering firm and the turbine-generator supplier.

Q. What is the total cost loadings and Allowance of Funds Used During Construction (AFUDC) for the Faraday Resiliency and Repowering Project?

A. The project cost loadings are approximately \$22.6 million and AFUDC is approximately \$19.3 million.

[35] Estimated costs incurred, not including AFUDC and loadings.

Q. Do you propose an adjusted depreciation schedule for Faraday in this case?

A. Yes. Since Faraday Units 7 and 8 effectively represent a new hydro plant, we expect that the life of these new assets will extend beyond the period of the current FERC license for the Clackamas River Project facilities. Therefore, we propose to extend the probable retirement and depreciable life end-date for the Faraday hydro plant, including the new Faraday Units 7 and 8 from 2055 to 2085. Additional detail regarding depreciation costs is provided in PGE Exhibit 200.

F. Strategic Importance of the Faraday Units 7 and 8

Q. Why is the non-emitting capacity provided by Faraday Units 7-8 so important?

A. As described above, the addition of Faraday Units 7-8 to PGE's capacity portfolio is critical given the regional capacity shortage due to the significant amount of dispatchable generation (i.e., coal and gas plants) that has been retired or decommissioned within the Western Electricity Coordinating Council (WECC) region during the last two decades and the related impact to energy markets and PGE's Power Operations.[36] As described in PGE Exhibits 300 and 400, the reduction in regional firm and dispatchable resources is causing a regional capacity shortage which manifests in the form of extreme price volatility and increases the number of scarcity price events during weather driven load excursions or other market events. For example, the Mid-C power market exhibited this type of behavior during 2021 and 2022 due to heat events that led Mid-C market power prices to reach extreme levels of over $500/MWh in 2021 and over $1000/MWh in 2022. Access to reliable generation from Faraday will help PGE's customers withstand such resource scarcity-driven price events.

[36] *See* detailed discussion regarding the changes to regional capacity resources landscape and the associated impacts in PGE Exhibits 300 and 400.

Q. Please discuss why constructing Faraday Units 7-8 is important in the context of recent decarbonization policies adopted in Oregon.

A. PGE's decarbonization strategy aligns with the aggressive emissions reductions required by Oregon law. In 2021, the Oregon legislature passed HB 2021, calling for transformational reductions in greenhouse gas (GHG) emissions from Oregon's electric power sector. HB 2021 requires PGE to reduce emissions to serve retail customers by 80% from a baseline amount[37] by 2030, 90% by 2035, and to eliminate GHG emissions by 2040. To achieve this, PGE anticipates procuring and integrating at least 3,000 MW of non-emitting resources and capacity by 2030, while reducing fossil fuel generation and purchases served to Oregon retail customers.[38] Faraday is particularly valuable in this context because it is a non-emitting capacity resource. The carbon reduction requirements under HB 2021 and the massive amount of non-emitting capacity that we anticipate needing to meet these requirements make retention and repowering of the Faraday hydro project even more critical as we seek to completely eliminate carbon emissions from our power supply portfolio by 2040. PGE needs resources like Faraday Units 7-8 to achieve significant emissions reductions while maintaining reliable and affordable electric service for customers.

[37] "Baseline" is the average annual emissions associated with electricity sold to retail customers in 2010, 2011, and 2012 as determined by Oregon DEQ.
[38] The estimate of additional non-emitting MW will be further refined in PGE's next IRP and CEP filings, expected in March 2023.

Q. Why are hydro resources such as Faraday so valuable in meeting Oregon decarbonization directives while maintaining reliable and affordable electric service for customers?

A. Aside from providing non-emitting energy, hydro resources present several unique beneficial attributes compared to or in relation to other renewables (e.g., wind and solar) that support the transition to renewable variable energy resources. Specifically, the hydro generation profile provides diversity and supports reliable energy deliveries during peak days when wind and solar resources might not be available. Additionally, hydro generation can be forecast in the medium term (3 to 6 months) and therefore it allows for increased generation predictability.

Q. Are there similar resources in the market that could easily be added to PGE's resource portfolio to replace Faraday?

A. No. Hydro generation in the WECC region has stayed relatively constant over the last 20 years.[39] Furthermore, it is not expected that new hydro resources will be added to the WECC regional generation stack because of the regulatory, environmental, and permitting complexities associated with building such resources. As previously described, given the renewable portfolio standards in the WECC region and the recently adopted emission reduction requirements in Oregon and Washington, hydro resources are extremely valuable. Thus, replacing the non-emitting hydro resource that is Faraday with a similar new resource or a capacity agreement would be extremely challenging and expensive in today's energy market environment with energy market prices that have increased dramatically in recent years, and are expected to continue to increase in future years.

[39] *See* Figures 1 and 2 in PGE Exhibit 400 reflecting very low or no annual change in hydro generation in the WECC between 2001 and 2022.

Q. Given the unanticipated delays and cost overruns, why were the decisions PGE made concerning the Faraday Resiliency and Repowering Project prudent?

A. We collectively have approximately 80 years of experience in this industry and believe the decisions PGE made and actions taken, based on information known or knowable at the time, to be prudent and reasonable in light of the circumstances. PGE's decision to pursue the rebuild and repowering of the 1907 Faraday Powerhouse was supported by FERC Staff, who found in their assessment report on PGE's March 2018 Clackamas River Project license amendment application the following:

> Based on our independent review and evaluation of the environmental and economic effects of the proposed action and the no-action alternative, we recommend the proposed action [rebuilding and repowering the 1907 Faraday Powerhouse] as the preferred alternative. We recommend this alternative because: (1) issuing an amendment of the project license would allow the licensee to continue operating the project as a beneficial and dependable source of electric energy; (2) increase the seismic stability of the Faraday Powerhouse and enhance the ability of the powerhouse to resist flooding during high flow events; and (3) the proposed environmental measures identified below would protect project resources.[40]

While we are disappointed that the project was delayed and is more costly than originally anticipated, we would make the same key decisions and take the same actions as we described in this testimony.

In closing, the Faraday hydro plant was and continues to be a vital and diverse clean energy resource that has served our customers extremely well for over 100 years. The new investments in this critical resource will ensure that Faraday will continue to benefit PGE customers and Oregon communities for generations to come.

[40] *See* Exhibit 810 - Environmental Assessment for Non-Capacity Amendment to License, Section 4.0, at page 42.

VI. Summary

Q. Please summarize your request for incremental generation investments and O&M expenses in this filing.

A. We request that the Commission approve PGE's 2024 forecast of $134.0 million in generation O&M costs (including IT generation-related expenses). The 2024 forecast represents a $15.8 million increase from 2022 costs due primarily non-labor costs escalation, increased maintenance costs, and increased IT costs. Additionally, we request that the Commission approve recovery of the costs associated with the Faraday Resiliency and Repowering Project.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
801C	PGE's 2024 Generation Resources
802C	PGE Plant Availability 2020-2022
803C	PGE Thermal Resource Generation
804	Major Maintenance Accruals
805C	Seismic Evaluation Report
806C	Powerhouse Upgrade Study
807C	Faraday Repower Turbine Selection Study
808C	Faraday Resiliency and Repowering Project – 2016 Economic Analysis
809C	Faraday Powerhouse Evaluation of Construction Proposals
810	Environmental Assessment for Non-Capacity Amendment to License

Exhibit 801 contains confidential information and is subject to

Modified General Protective Order 23-039.

Information provided in electronic format only.

Exhibit 802 contains confidential information and is subject to

Modified General Protective Order 23-039.

Information provided in electronic format only.

Exhibit 803 contains confidential information and is subject to

Modified General Protective Order 23-039.

Information provided in electronic format only.

Plant	2022 actuals	UE 394 Approved MMAs	2024 Budget	2024 GRC revised	Variance (2022 Actuals-2024 revised)	Annualized Variance (2022 GRC-2024 GRC)	Variance 2024 Budget vs 2024 Revised
Carty	6,398,086	6,850,948	6,850,947	7,543,541	1,145,455	692,593	692,594
Coyote	3,188,850	3,464,004	3,464,005	1,875,942	(1,312,909)	(1,588,062)	(1,588,064)
PW1	4,980,351	4,453,956	3,710,378	6,561,113	1,580,762	2,107,157	2,850,735
PW2	791,488	773,805	773,803	1,160,459	368,971	386,654	386,656
Colstrip					-	-	-
KB Pipeline Pigging	(38,422)	143,100	(104,558)	26,764	65,187	(116,336)	131,323
Total	**15,320,354**	**15,685,812**	**14,694,576**	**17,167,819**	**1,847,465**	**1,482,006**	**2,473,243**
					1,847,465		

Plant	2022 GRC revised
Carty	6,850,948
Coyote	3,464,004
PW1	4,453,956
PW2	773,805
Colstrip	637,960
KB Pipeline Pigging	143,100
Total	**16,323,773**

PGE Accounts	2022 actuals	2024 Budget	2024 GRC revised	Variance (2024 Actuals-2024 revised)	Variance 2024 Budget vs 2024 Revised
MMAs in Account 4560002	1,962,199	(1,461,881)	(1,461,881)	(3,424,080)	-
MMAs in Generation O&M Accounts	13,358,155	16,156,456	18,629,699.67	5,271,545	**2,473,243**
check	-	-	-	-	-

-

PGE Exhibit 200 (Revenue Requirement) MMA Adjustment in		
2024 Budget	**2024 REVISED**	**Adjustment**
14,694,576	17,167,819	**2,473,243**

1. Total MMA amounts in Generation O&M Accounts and Account 4560002 (Other Revenue)

PGE Exhibit 800 (Generation O&M) MMA Adjustment[2]		
2024 Budget	**2024 REVISED**	**Adjustment**
16,156,456	18,629,700	**2,473,243**

2. Includes only Generation O&M Accounts

COLSTRIP*

	2022 actuals	UE 394 Approved MMAs	2024 Budget	2024 revised	Variance (2022 Actuals-2024 revised)	Annualized Variance (2022 GRC-2024 GRC)	Variance 2024 Budget vs 2024 Revised
Colstrip	$ 625,616	$ 637,960	$ 637,960	$ 975,672	$ 350,057	$ 337,712	$ 337,713

O&M / Oth Revenue Split					
MMAs in Account 4560002	625,616	334,400	334,400	(291,216)	-
MMAs in Generation O&M Accounts	-	303,560	303,559.57	303,560	**(0)**

*** Note: The Colstrip MMA cost is not included in this case as PGE now recovers these costs through in the Schedule 146**

Exhibit 805 contains confidential information and is subject to

Modified General Protective Order 23-039.

Information provided in electronic format only.

Exhibit 806 contains confidential information and is subject to

Modified General Protective Order 23-039.

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Exhibit 807 contains confidential information and is subject to

Modified General Protective Order 23-039.

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Exhibit 808 contains confidential information and is subject to

Modified General Protective Order 23-039.

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Exhibit 809 contains confidential information and is subject to

Modified General Protective Order 23-039.

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ENVIRONMENTAL ASSESSMENT
FOR NON-CAPACITY AMENDMENT TO LICENSE

Clackamas River Hydroelectric Project—FERC Project No. 2195-161

Oregon

Federal Energy Regulatory Commission
Office of Energy Projects
Division of Hydropower Administration and Compliance
888 First Street, NE
Washington, D.C. 20426

March 2019

TABLE OF CONTENTS

1.0 INTRODUCTION

Application Type:	Non-capacity related amendment of license
Date Filed:	March 16 and 19, 2018, and supplemented April 4, 18 and May 2, 2018.
Applicant's Name:	Portland General Electric Company (PGE)
Waterbody:	Clackamas River
County and State:	Clackamas County, Oregon
Federal Lands:	There are currently 3,019.9 acres of Lands of the United States within the Clackamas Project (Project) boundary, 2,756.0 acres of which are federal lands within the Mt. Hood National Forest, under the jurisdiction of the U.S. Forest Service (Forest Service) and 263.9 acres administered by the U.S. Department of the Interior's (Interior) Bureau of Land Management (BLM). Under PGE's proposal in this application, the amount of federal land occupied by the Project would not change.

1.1 Purpose of Action

PGE owns and operates the 138.8-megawatt (MW) Clackamas Project. The Project consists of four developments: Oak Grove, including Timothy Lake and Lake Harriet dams; North Fork; Faraday; and River Mill. The Oak Grove development is located on the Oak Grove Fork of the Clackamas River, and the other three developments are located on the mainstem of the Clackamas River. On December 21, 2010, the Federal Energy Regulatory Commission (Commission) issued an Order Issuing New License.[1]

PGE seeks to improve the Faraday development by reconstructing the existing powerhouse to increase its seismic stability, installing flood protection structures to prevent flooding during high flow events, and replacing the five (5) 110-year-old turbines with two (2) modern units, without any change to the authorized installed or hydraulic capacities of the Project.

[1] *Portland General Electric Company*, 133 FERC ¶ 62,281 (2010), *order on reh'g*, 134 FERC ¶ 61,206 (2011).

The Proposed Action would increase turbine efficiency. The proposed rebuild of the powerhouse would increase the likelihood that the powerhouse could remain operational following seismic activity, thereby improving the reliability of generation and PGE's ability to provide power to its customers. The flood-protection measures would reduce the risk of an inadvertent release of lubricants from the powerhouse into the river. Under existing conditions, PGE shuts down the powerhouse and drains equipment when flows are excessive. This is a time-consuming and expensive undertaking Statutory and Regulatory Requirements.

1.1.1. Clean Water Act

Under section 401(a)(1) of the Clean Water Act (CWA)[2], a license applicant is required to obtain certification from the applicable state pollution control agency, in this case the ODEQ, verifying that the proposed amendment would comply with applicable water quality standards of the State of Oregon or a waiver of such certification. A waiver occurs if the state agency does not act on a request for certification within a reasonable period of time, not to exceed one year after receipt of such request.

On March 16, 2018, PGE applied to the Oregon Department of Environmental Quality (ODEQ) for section 401 certification for the proposed action. ODEQ received this request on March 19, 2018.

On July 2, 2018, the ODEQ granted a CWA 401 certification for the proposed amendment to the project. The WQC was filed with the Commission on February 14, 2019. Specific to the proposed amendment, the certification includes 15 conditions; one of which is general (Amendment Certification Condition 15) and are not discussed further.

Amendment Certification Conditions 1 and 2 require the licensee to implement the revised Water Quality Management and Monitoring plan and the Contaminated Media Management Plan, respectively, as cited in the licensee's amendment application.

The remaining Amendment Certification Conditions require: (1) preparation and implementation of an erosion control plan (Condition 3); prohibition from placing biologically harmful materials and construction debris where such materials could enter waters of the state (Condition 4); provide spill prevention for fueling, operating, maintaining and storing vehicles and equipment by maintaining a buffer of at least 150 feet away from any waters of the state (Condition 5); report the discharge of petroleum products, chemicals, or any deleterious materials have been, or have the potential to be, discharged in state waters (Condition 6); provide protection for riparian, wetland and shoreline vegetation in the authorized project area (Condition 7); provide notification to the ODEQ one week prior to the start of construction (Condition 8); implementation of

[2] 33 U.S.C. § 1341(a)(1)

the terms of the post-construction stormwater management plan (Condition 9); implementation of the best management practices (BMP) as proposed in the post-construction stormwater management plan (Condition 10); implementation of the effective operation and maintenance practices for the lifetime of the proposed facilities (Condition 11); performing in-water work only within the Oregon Department of Fish and Wildlife (Oregon DFW) window to protect fish and wildlife resources (Condition 12); provide unobstructed fish passage at all times during any authorized activity (Condition 13); and demolition work below ordinary high water level must be performed behind a temporary cofferdam (Condition 14).

1.1.2. Endangered Species Act

Section 7 of the Endangered Species Act (ESA) requires federal agencies to ensure that their actions are not likely to jeopardize the continued existence of endangered or threatened species or result in the destruction or adverse modification of the critical habitat of such species. On May 8, 2017, PGE requested designation as the Commission's non-federal representative for the purpose of informal consultation with the National Marine Fisheries Service (NMFS), pursuant to Section 7 of the ESA. On May 25, 2017, the Commission designated PGE as the Commission's non-federal representative in this proceeding. Since that time, PGE has informally consulted with NMFS regarding the Proposed Action and measures to minimize or avoid adverse effects on ESA listed species. This informal consultation included a meeting between NMFS representatives and PGE representatives on February 2, 2018 in Lacey, Washington.

Based on the analysis in the Biological Assessment adopted and issued by the Commission on June 19, 2018, and the protection and mitigation measures proposed as part of the Proposed Action to minimize and avoid adverse effects, Commission staff concludes that the Proposed Action May Affect but is Not Likely to Adversely Affect Lower Columbia River (LCR) Chinook salmon, Upper Willamette River Chinook salmon, LCR coho salmon, and LCR steelhead. Additionally, staff concludes that the Proposed Action May Affect but is Not Likely to Adversely Affect designated critical habitat for LCR Chinook salmon, UWR Chinook salmon, LCR steelhead, and LCR coho salmon.

In addition, PGE contacted the U.S. Fish and Wildlife Service (USFWS) regarding the presence of ESA-listed species under the jurisdiction of USFWS within the Action Area. In response, in an email dated February 23, 2018, USFWS confirmed that, although there is a potential for ESA-listed bull trout (*Salvelinus confluentus*) to be present within the Action Area, the population in the Clackamas River is a non-essential experimental population, which means it is treated as "proposed" for purposes of ESA Section 7. USFWS also confirmed that there are no additional ESA-listed species under USFWS jurisdiction that are present in the Action Area that would be affected by the Proposed Action.

1.1.3. Magnuson-Stevens Fishery Conservation and Management Act

Section 305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act requires federal agencies to consult with NMFS on all actions that may adversely affect Essential Fish Habitat (EFH).

The Pacific Fisheries Management Council (PFMC) designated EFH for Chinook salmon and coho salmon as part of the *Pacific Salmon Plan*, issued by the PFMC in 1999. The Action Area includes areas designated as EFH for various life-history stages of Chinook salmon and coho salmon. Based on the information provided in the *Biological Assessment* adopted and issued by the Commission on June 19, 2018, the Proposed Action is not expected to have adverse effects on EFH designated to Chinook salmon and coho salmon.

1.1.4. Coastal Zone Management Act

Under section 307(c)(3)(A) of the Coastal Zone Management Act (CZMA), 16 U.S.C. § 1456(3)(A), the Commission cannot issue a license for a project within or affecting a state's coastal zone unless the state's CZMA agency concurs with the applicant's certification of consistency with the state's CZMA program. Because the Project is not located within Oregon's Coastal Management Zone, and would not affect coastal resources. Therefore, no consistency certification is needed.

1.1.5. National Historic Preservation Act

Section 106 of the National Historic Preservation Act (NHPA)[3] and its implementing regulations[4] requires that every federal agency "take into account" each of its undertakings as they could affect historic properties. Historic properties are districts, sites, buildings, structures, traditional cultural properties, and objects significant in American history, architecture, engineering, and culture that are eligible for inclusion in the National Register of Historic Places (National Register).

The approved Historic Properties Management Plan for the Project indicates that the Faraday Powerhouse is considered to be a historic contributing resource. Therefore, the proposed removal of the Faraday Powerhouse would be considered an undertaking pursuant to section 106 of the NHPA. In addition, the Commission has determined that this undertaking would adversely affect the Faraday Powerhouse and many of the associated facilities, which are contributing features to the Clackamas Hydroelectric Project (determined eligible for the National Register in June 2003). Accordingly, on

[3] 54 U.S.C. §§ 306108 et seq. (2016). The National Historic Preservation Act was recodified in Title 54 in December 2014.

[4] 36 C.F.R. Part 800 (2018).

May 25, 2017 the Commission designated PGE as its non-federal representative for the purpose of conducting consultation with the Oregon State Historic Preservation Office (Oregon SHPO) under Section 106 of the NHPA. PGE attended consultation meetings at Oregon SHPO's Salem office on February 16, 2017 and January 11, 2018.

To meet the requirements of section 106, staff executed a Memorandum of Agreement (MOA) to mitigate the adverse effect of removing the Faraday Powerhouse and many of the associated facilities. The terms of the MOA ensure that the PGE addresses and mitigates adverse effects. The Commission signed the MOA on November 14, 2018, and the Oregon SHPO signed the MOA on November 26, 2018. The licensee and the BLM signed the MOA as concurring parties on November 26 and December 3, 2018, subsequently. Commission staff recommend incorporating the executed MOA into any amendment order for the project.

1.2 Pre-Filing Consultation and Public Notice

As required by Commission regulations, this license amendment application has been prepared using a three-stage consultation process with the appropriate resource agencies and other stakeholders. PGE initiated Stage 1 of its three-stage consultation with the distribution, on April 19, 2017, of its proposal to upgrade the Faraday Powerhouse.

A formal meeting and facility tour with stakeholders was held on May 19, 2017 to discuss PGE's Proposed Action and the proposed license amendment application process and schedule. As required by Commission regulations, a meeting transcript was recorded. With concurrence from the primary resource agencies, the comment period for the proposal document ended on June 19, 2017.

Stage-2 consultation began with PGE's issuance to stakeholders of a Draft Application for Non-Capacity Amendment of License on October 3, 2017, which initiated a 90-day comment period that ended on January 3, 2018. PGE incorporated its responses to stakeholder comments and preliminary terms and conditions for the amended license into the Final Application for Non-Capacity Amendment of License, which was filed on March 16, 2018.

On May 9, 2018, the Commission issued a public notice of the PGE's application for amendment soliciting comments, motions to intervene, protests, recommendations, terms and conditions

On May 17, 2018, the Oregon Department of Environmental Quality filed a motion to intervene. On May 24, 2018 the National Marine Fisheries Service and the U.S. Forest Service each filed a notice of intervention. On June 1, the Oregon Water Resources Department filed a notice of intervention. On June 4, 2018, the Oregon Department of Fish and Wildlife filed a motion to intervene and comments on the application. On June 8, 2018, American Whitewater filed a motion to intervene and comments on the application. On June 15, 2018, the U.S. Environmental Protection Agency filed untimely comments on the application. Comments filed in response to the notice are addressed in the appropriate resource sections of this EA.

2.0 PROPOSED ACTION AND NO-ACTION ALTERNATIVE

2.1 No-Action Alternative

Under the No-Action Alternative (i.e., denial of the amendment by the Commission) Project facilities would remain unchanged, except for any future modifications called for by the existing license and routine maintenance activities. Operation of the Faraday Powerhouse would be less efficient than it would be under the Proposed Action, and reductions of seismic risk associated with the existing powerhouse and flood-protection measures would be foregone (see Section 1.2). In addition, improved survival rates for the low numbers of juvenile salmonids passing through the Faraday Powerhouse, and the benefits associated with proposed coarse sediment augmentation, would not be realized. The Commission uses the No-Action Alternative as the baseline environmental condition for comparison with the Proposed Action.

2.1.1. Existing Faraday Development Facilities

The Faraday Development, located downstream of North Fork Dam on the mainstem Clackamas River and has an installed capacity of 35.92 MW. Water releases from North Fork Dam flow down the Clackamas River approximately 1.6 miles to the Faraday Diversion Dam, which impounds a reservoir with a gross storage capacity of approximately 1,200 acre-feet. A gated intake diverts part of the river's flow through a 0.5-mile-long, 23-foot-diameter tunnel and then through a 0.67-mile-long canal into Faraday Lake, the forebay for the Faraday Powerhouse. Faraday Lake has a gross storage capacity of approximately 484 acre-feet, including the canal and tunnel. A concrete intake structure and an emergency spillway are located at the downstream end of the forebay. Intake gates are provided for each of the six penstocks serving the six turbine-generator units. Four, 8-foot-diameter riveted steel penstocks and one 9-foot-diameter riveted steel penstock lead to the original five-unit powerhouse to operate the five double horizontal Francis-type turbines. A 14-foot-diameter welded steel penstock leads to the newer semi-outdoor portion of the powerhouse to operate a vertical Francis-type turbine. The Faraday Powerhouse discharge joins the Clackamas River's flow from the Faraday bypass reach and then enters Estacada Lake.

2.1.2. Operation of the Existing Faraday Development

PGE operates the Faraday Powerhouse according to criteria defined in the *Clackamas Project Operating Plan*, as revised in 2016[5]. The water level in Faraday Lake is normally maintained near the full pool elevation to maximize head for power generation. The operating limits for the Faraday forebay are shown in Table 1.

Table 1. Faraday Lake (forebay) operating levels.

Date	Forebay Elevation, ft	Notes
Oct 1 – Jun 30	523.5 maximum 511.7 minimum	Limits are shown in PGE Datum, which is 1.5 ft above mean sea level. Lake elevation lowered from July 1 to September 30 to establish channelized flow within berms per CWA Section 401 Certification Condition 8(l)(1).
Jul 1 – Sep 30	520.5 maximum 511.7 minimum	

The Faraday Powerhouse is typically operated to pass inflow, with some re-regulation of flows when the upstream North Fork Powerhouse is operated in a peaking mode. Pursuant to the June 18, 2003, license amendment, 103 FERC ¶62,161, Project hydraulic capacity is 5,704 cfs. The minimum flow through the Faraday Powerhouse is 120 cfs.

Condition 8(l)(1) of the Section 401 water quality certification (Appendix A to the Project License) required PGE to achieve a temperature reduction of approximately 0.5 ˚C during the period July 1 to September 30 at the Faraday powerhouse tailrace. To satisfy this requirement, PGE excavated a channel in the middle of Faraday Lake and confines the majority of flow within this excavated channel by reducing the water surface elevation of the lake by about 2 feet from July 1 through September 30 of every year (Table 1).

2.2 Proposed Action

2.2.1. Proposed New Faraday Powerhouse

Turbine Replacement

PGE plans to replace existing turbine units 1 through 5 with two vertical Kaplan turbines. Unit 6 would remain in place. Each unit would discharge into a draft tube that would exit into the powerhouse tailrace.

[5] The revised Project Operating Plan was approved by the Commission on November 10, 2015, 153 FERC ¶ 62,097.

Intakes and Penstocks

The 8-foot-diameter penstocks for Units 1 through 4 and the 9-foot-diameter penstock for Unit 5 would be removed, and the Units 2, 3, 4, and 5 penstocks would be replaced with two new 9-foot-diameter, welded-steel penstocks. The concrete supports and intermediate concrete retaining walls would be removed along with the five penstocks and replaced with new reinforced concrete supports and retaining structures as required. The new penstocks would utilize the 8-foot diameter intakes for Units 2, 3, 4 and 5. Intake 1 would be capped off and not be used in the future, because flow must make a sharp turn before entering the intake, which results in head loss and flow limitations.

Each penstock would be designed so that flow and water velocity would be nearly identical at the point where the water from the four intakes merges into two penstocks (referred to as reverse bifurcations) that lead to the two new turbine units. The radius of each reverse bifurcation would be designed to minimize flow disturbances, and shear forces are expected to be nominal. The provisional estimate of water velocity at the entrance point of each reverse bifurcation is 9.0 ft/s, and downstream of each reverse bifurcation estimated velocity is 14.1 ft/s.

At the intake, a new steel section would be inserted into the existing steel penstock and seal-welded flush with the steel of the upstream headgate. The annular space between the new steel penstock and the existing penstock would be grouted. This would allow the entire penstock from the intake headgate to the new unit to be made of new steel. The new penstocks would include vents, manholes at the top and bottom for access, and a cathodic protection system to prevent corrosion, if required.

Debris Management

The existing trashracks for intakes 4 and 5 show moderate corrosion and would be replaced. The existing manual trash-rake would be upgraded and replaced with an automated rake and trash conveyance system.

Headgates

Headgates installed in 2012 would be reused. The five rack-and-pinion operators and the associated enclosures would be removed, and new screw-stem actuators would be mounted outdoors on the intake deck. The screw-stem actuators would be capable of driving down the headgates under flow to isolate the penstocks from the forebay. The new units would be designed to accept reasonably long periods of overspeed to allow for headgate closure to stop unit flow if the wicket gates and turbine inlet valves fail to close. The new screw-stem actuators and their anchoring systems would need to be specified to be able to drive the headgates closed under full runaway flow.

Powerhouse

The new powerhouse design would meet current earthquake requirements and desired factors of safety. The design would include measures to ensure that flood protection (see next section) is provided above historic flow levels and provide safer means of performing maintenance resulting from best practices improvements incorporated into the design.

The majority of demolition would occur above the ordinary high waterline. Any work below the waterline would be performed behind a cofferdam (see Cofferdam Construction below), thereby preventing material from entering the river. PGE has performed a hazardous materials survey of the powerhouse site. The plan would be incorporated into the general construction contract implemented by the construction contractor, with oversight provided by PGE. Implementation of the Contaminated Media Plan filed with the application is required by WQC condition 2.

The new vertical turbine units would require significant excavation to accommodate new draft tubes, scroll cases, and embedded penstock sections. A crane would be used to remove the existing units and other equipment. The powerhouse superstructure would then be removed. To make room for installing new embedded parts for the turbines, the substructure concrete and supporting rock would be demolished/excavated by drilling, blasting, and splitting as required.

The new powerhouse would be a reinforced concrete structure with a sidewall elevation set above the flood protection elevation to function as a floodwall. The wall structure would support a new bridge crane and a steel roof. A new Unit 6 access road would be constructed on fill material placed behind the new powerhouse at approximately the same elevation as the existing access bridge.

The Proposed Action would affect approximately 31,000 ft^2 of surface area adjacent to the river, which would include replacing buildings, constructing the floodwall, and paving. The existing powerhouse (occupying an area of 9,970 ft^2) and three small storage and shop outbuildings (occupying an area of about 2,000 ft^2) would be demolished. The new powerhouse would occupy approximately 10,100 ft^2 of land adjacent to the river that is currently occupied by the existing powerhouse. The outbuildings would not be replaced. The land surface area previously occupied by the buildings to be demolished but not occupied by the new powerhouse would be graded and paved.

Deep excavations would be required for the new powerhouse, up to about 20 ft deeper than the existing powerhouse and about 30 ft below normal river water level. It is estimated that 6,000 yd^3 of bedrock would be removed for the new powerhouse foundation (the bedrock to be removed is not within the river channel; tailrace excavation is addressed in a subsequent section). It is anticipated that a construction ramp would be required to access the powerhouse foundation, and sumps would be installed within the excavated area to collect stormwater and groundwater that enter the excavated area. This water would be observed for turbidity and treated as necessary prior to release to the river.

Flood Protection Improvements

The existing powerhouse for Units 1 through 5 is partially protected from flooding by concrete and wooden floodwalls. The Proposed Action would result in improved flood protection because a concrete floodwall would be constructed around the entire new powerhouse up to the elevation of the deck of the Unit 6 powerhouse. Additionally, a floodwall would extend upstream from the powerhouse to protect the substation and parking area next to the new powerhouse.

Access Improvements to Unit 6

A bridge over the penstocks for Units 1 through 5 currently provides access to Unit 6. As part of the Proposed Action this bridge would be removed to allow installation of the new penstocks, and the area behind the powerhouse would be filled to the elevation of the bridge deck creating a large access road and laydown area. New drainage systems would be installed to manage surface water from the area upstream of the powerhouse (PGE prepared a Post-Construction Stormwater Management Plan, as noted in a subsequent section). The upstream powerhouse wall would be designed to retain the fill material and surcharge loads.

Mechanical and Electrical Auxiliary Systems

New mechanical systems would be installed in the powerhouse for heating, filtered ventilation, air conditioning for the area enclosing the switchgear and control interfaces, draft tube dewatering, sump pumps, oil-water separators, the septic system, service water, and compressed air. A dedicated station service transformer would power these systems and all powerhouse lighting.

Electrical Power and Control Systems

New switchgear, relaying, and protection packages would be supplied with each unit. The new switchgear would be housed in metal enclosures and mounted to the floor of the new powerhouse. The control system for the new units would include a programmable logic controller (PLC) and a dedicated digital governor to control the units.

The new controls would be located within the existing Unit 6 Powerhouse control room. Each turbine would have a hydraulic power unit for gate actuation. The existing Unit 6 battery bank has recently been upgraded and may be used to provide backup control power to the new units' control systems, or a separate DC system for the new units would be installed.

Substation Interconnection

The leads from the switchgear would be routed to the existing 11kV switchyard adjacent to the powerhouse. Existing transmission lines from the 11kV switchyard to the Faraday substation on the north bank of the river would be reused along with their supports. The switchgear leads would run in an underground conduit to the existing 11kV switchyard and would connect to the Faraday Substation at the same point as the existing units 1 through 5. No additional transmission lines would be installed as part of the Proposed Action; the action would only involve installing new medium voltage underground cables and separating the two step-up transformers at the switchyard.

Faraday Lake Drawdown during Forebay Construction

Implementation of the Proposed Action would require an outage of Unit 6, during which time Faraday Lake would be drawn down completely. Drawing down Faraday Lake would require water ordinarily routed to Faraday Lake to instead be passed over the Faraday Diversion Dam and into the Faraday Diversion Reach. Section 2.2.3 provides an explanation of how Faraday Lake would be draw down and refilled to avoid impacts to salmonids.

Tailrace Construction, Cofferdam Installation and Deconstruction, and Temporary Low-Flow Fish Passage Channel

A cofferdam would be required to isolate the tailrace, so that bedrock can be excavated and the new powerhouse installed. The installation and deconstruction of the cofferdam, construction in the powerhouse tailrace, and actions undertaken to provide fish passage during the construction period are described below. Measures proposed to be implemented to avoid adverse effects associated with these activities are described in Section 2.2.3.

Anadromous salmonids migrate upstream to the entrance of the 1.9-mile-long fish North Fork fish ladder extending from the south bank of the river immediately downstream of the Faraday diversion dam to the North Fork reservoir. To provide unimpeded fish passage during construction activities, a temporary low-flow fish passage channel would be excavated upstream of the Faraday Powerhouse tailrace. The first step would be to construct an access road leading from the existing paved surface on the south side of the river. After establishing access, trees and shrubs would be cleared from the portion of the channel to be excavated. Material excavated from the channel would be used to construct a temporary flow diversion berm to direct flow into the excavated channel. The geometry and placement of the low-flow channel were selected to provide velocities and depths, that were identified in collaboration with the Fish Agencies (i.e., ODFW, NMFS, and USFWS), to be conducive to upstream fish passage. The estimated volume of bed material to be excavated to form the fish channel is 350 yd^3.

A hybrid sheet-pile and cellular, earth-fill cofferdam would be constructed to enclose the powerhouse tailrace so construction activities can be conducted in the dry. The cellular cofferdam would be installed incrementally in a downstream direction using steel members filled with coarse sediment. Coarse sediment would be transported from a PGE-owned mining site located on a terrace adjacent to the lower Clackamas River (i.e., the site where coarse sediment is mined) to PGE's FERC-approved coarse sediment augmentation program for the lower Clackamas River. Coarse sediment particles used to fill the cofferdam units would be sifted and range in size from 0.25 inches to 6.0 inches. The first cellular unit would be placed from the shore, and subsequent units would be placed by equipment perched on previously installed units. The cofferdam units would be put into place primarily in the dry on the mid-channel island. The island is expected to be largely dry given the anticipated flows at the expected time of construction (i.e., May 2019), and because Unit 6 would be operating, most flow would be routed around the installation area.

Following construction of the cellular portion of the cofferdam, the sheet-pile section of the cofferdam would be installed on the west side of the tailrace adjacent to Unit 6. Before installing the sheet-pile section, the west side of the cofferdam area would be left open for at least 12 hours to provide egress for any salmonids in the tailrace area surrounded by the cellular cofferdam. The substrate where the sheet-pile portion of the cofferdam would be installed consists of bedrock. Because of this, piles cannot be driven into the substrate. PGE would use divers or a barge-mounted drill rig to bore into the rock and set the piles with grout. The drill slurry and rock powder would be pumped to the surface and stored in a tank for subsequent disposal. No slurry would be released into the river. Grout would be isolated from the water column until it is cured. When the cofferdam is completed, pumps would be installed on the tailrace side of the cofferdam and used to dewater the tailrace prior to beginning construction activities associated with the new powerhouse. Completing construction would require excavating the tailrace to accommodate the draft tubes associated with the new vertical Kaplan units. The estimated volume of material to be excavated from the tailrace is 4,600 yd^3.

When construction in the tailrace has been completed, the pumps behind the cofferdam would be deactivated and removed, and the area would be allowed to fill with water. The sheet-pile section of the cofferdam would be removed, after which the steel members of the cellular cofferdam would be removed moving in an upstream direction. Coarse sediment would be allowed to exit the cofferdam units when the north-side steel frames are lifted. The inner wall of the cellular cofferdam would be kept in place while coarse sediment is being manipulated by machinery on the mid-channel island. Because flows would be low in the Faraday diversion reach during late summer/early fall, most of the deconstruction should be completed in the dry. The sediment is expected to move downstream to the channel just upstream of Estacada Lake, where it would combine with existing coarse sediment to improve anadromous salmonid spawning habitat. When the cofferdam is fully removed, coarse sediment from the cofferdam units would be contoured so that it can be recruited to the river during subsequent high flows, the temporary diversion berm would be removed, the low-flow fish passage channel would be filled in (i.e., the channel would be restored to approximately its preexisting condition), and the access road would be decommissioned.

Design of Post-Construction Impervious Area and Surface Drainage

Construction associated with the Proposed Action would involve the installation of a post-construction stormwater collection system, which would collect runoff from pre-existing and newly paved areas. The system would involve passive oil-water separator systems to collect and treat roadway contaminants. The design would accommodate runoff from the roadway to the new powerhouse, enabling it to be treated and discharged, even when the river level is higher than the ground level uphill of the flood wall. PGE filed a proposed Post-Construction Stormwater Management Plan[6] filed with the Commission concurrently with PGE's Request to ODEQ for a Determination Pursuant to ORS 468B.045 (request for § 401 water quality certification). Implementation of the Post-Construction Stormwater Management Plan is required by the ODEQ WQC.

2.2.2. Proposed Faraday Powerhouse Operations

PGE proposes no changes to the operating protocol required by the existing license for the Faraday Development. The Faraday Development would continue to operate according to the requirements of the existing Project license, as identified in Section 2.1.2.

2.2.3. Proposed Environmental Measures

Construction-Related Measures

Water and Aquatic Resources

[6] The proposed Post-Construction Stormwater Management is included with the Water Quality Monitoring Plan filed with the Application for Non-Capacity Related Amendment of License for the Clackamas River Hydroelectric Project No. 2195 (Project) Part 3 of 4: Exhibit E – Appendix 1, dated March 16, 2018.

Low-Flow Fish Passage Channel and Flow Diversion Berm

As noted above, to provide fish passage during the construction of the new powerhouse, PGE would excavate a low-flow, fish passage channel located upstream of the Faraday Powerhouse tailrace and use excavated sediment to construct a temporary flow diversion berm to route water into the excavated channel. Hydraulic modeling was used to design the low-flow channel so that it provides velocities and depths (which were identified in collaboration with the Fish Agencies) that would be conducive to upstream fish passage.

To avoid short-term disturbance to juvenile salmonids potentially occurring in the area to be excavated, PGE biologists would conduct a pre-excavation reconnaissance to evaluate whether fish salvage is warranted. If so, salvage would be conducted using agency-approved and permitted methods (analogous to those described below for the drawing down of Faraday Lake). However, the vast majority of anadromous salmonids from the upper basin are bypassed around this reach of the river because most juvenile fish from upstream are collected by PGE's downstream passage facilities in the North Fork forebay. In addition, most fish produced downstream of the Faraday Diversion Dam originate downstream of Faraday Powerhouse and tend to move into Estacada Lake to find rearing habitat. Also, substrate in the area to be excavated consists primarily of a mid-channel, vegetated bar and in-channel boulders. As a result, salmonid rearing habitat in the area is of marginal quality. To avoid short-term interference with adult salmonid upstream passage, excavation of the low-flow channel and flow diversion berm would be conducted over a short period, expected to be one day. When excavating equipment leaves the river, full fish passage would be in place.

To avoid impacts associated with potential increases in turbidity, PGE would implement an ODEQ-approved Water Quality Monitoring Plan[7], with monitoring protocol and turbidity thresholds at which channel excavation activities would cease and corrective measures would be enacted. The Water Quality Monitoring Plan is required by condition 3 of the WQC.

To avoid short-term impacts due to heavy equipment operating near and within the channel, PGE would employ relevant best management practices (BMPs) identified by NMFS in its Biological Opinion for the Clackamas River Project (NMFS 2010).

[7] The proposed Water Quality Monitoring plan is included in the Application for Non-Capacity Related Amendment of License for the Clackamas River Hydroelectric Project No. 2195 (Project) Part 3 of 4: Exhibit E – Appendix 1, dated March 16, 2018.

Construct Cofferdam around the Faraday Powerhouse Tailrace

To avoid short-term disturbance of juvenile salmonids in the area where the cofferdam would be installed, PGE biologists would conduct reconnaissance to evaluate whether salvage of any juvenile fish is necessary. If so, salvage would be conducted using agency-approved and permitted methods (analogous to those described below for the drawing down of Faraday Lake). As noted above, however, the vast majority of juvenile anadromous salmonids from the upper basin are bypassed around this reach, and most fish produced downstream of the Faraday Diversion Dam originate below the Faraday Powerhouse and tend to move into Estacada Lake to find rearing habitat. Also, the majority of the cellular portion of the cofferdam should be installed in the dry on a mid-channel island, as explained previously, thereby preventing any disturbance of juvenile salmonids.

Cellular cofferdam units would be placed into the channel and onto the mid-channel island incrementally, thereby giving any adult fish in the vicinity ample opportunity for egress, so any short-term impacts would be avoided. To avoid potential disruption of upstream passage through the reach adjacent to the cofferdam, water would be flowing through the excavated, low-flow channel, which would provide an area of suitable depths and velocities for adult fish migration during the cofferdam construction period.

During the construction of the cofferdam, PGE biologists, or a representative trained by PGE biologists, would conduct visual observations each morning to ensure that no fish in the vicinity of the construction area are showing signs of delay. If signs of delay are observed, PGE would notify the Fish Agencies as soon as possible within 24 hours and collaborate with the Fish Agencies to identify appropriate actions to be implemented to minimize the delay.

Installing the cellular portion of the cofferdam would require some leveling of the substrate so that the steel structures containing the coarse sediment would be stable. Noise associated with this action is expected to be well below the 150 dBRMS threshold for fish behavioral effects identified by the Washington State Department of Transportation (WSDOT)[8]. To avoid short-term disturbance to or injury of salmonids resulting from loud noise during installation of the sheet-pile portion of the cofferdam, PGE would use divers or a barge-mounted drill rig to bore into the bedrock and set the piles with grout. The drill slurry and rock powder would be pumped to the surface and

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[8] *Biological Assessment Preparation for Transportation Projects - Advanced Training Manual*, Chapter 7, Noise Impact Assessment, January 2018

https://www.wsdot.wa.gov/Environment/Biology/BA/BAguidance.htm#Manual stored in a tank for subsequent disposal. No slurry would be released into the river. PGE would use a bubble curtain to keep fish out of the area where the drilling is taking place. Grout would be isolated from the water column until it is cured.

Short-term stranding or trapping of fish in the area enclosed by the cofferdam would be avoided. Before the tailrace construction area is fully closed off by the sheet-pile portion of the cofferdam near Unit 6, PGE would allow at least 12 hours for any fish within the tailrace behind the cofferdam to exit the area. After this, PGE biologists would walk/float the tailrace area to induce any remaining fish to leave, although it is unlikely that fish would attempt to hold in the tailrace at this time, because flow into the area would have long been discontinued. When the cofferdam is completed, water would be pumped out of the area surrounded by the cofferdam. To avoid impacts, PGE would screen the intakes of the pumps used to dewater the tailrace so that no fish are entrained. At this time, PGE biologists would conduct reconnaissance to evaluate whether salvage of any juvenile fish is necessary. If so, salvage would be conducted using agency-approved and permitted methods (analogous to those described below for the drawing down of Faraday Lake).

To avoid short-term impacts associated with the operation of heavy equipment, PGE would minimize the amount of time construction equipment enters the river channel. The first cellular unit would be placed from the shore, and subsequent units would be placed by equipment perched on previously installed units. The cofferdam units would be put into place primarily in the dry on the mid-channel island. The island is expected to be largely dry given anticipated flows at the expected time of construction (i.e., May 2019), and because Unit 6 would be operating, which would result in most flow being routed around the installation area. In addition, PGE would employ relevant BMPs identified by NMFS in its Biological Opinion for the Clackamas River Project (NMFS 2010).

To avoid impacts associated with potential increases in turbidity, PGE would implement an ODEQ-approved Water Quality Monitoring Plan, with monitoring protocol and turbidity thresholds at which construction activities would cease and corrective measures would be enacted.

Drawing Down Faraday Lake

To minimize turbidity and fish stranding in Faraday Lake during construction-related drawdown, water surface elevation would be lowered at a rate of approximately 0.1 foot/hour. This drawdown rate is expected to allow fish, including juvenile Pacific lamprey, to follow the declining water level to the downstream end of Faraday Lake, where they would either exit the lake through the powerhouse/spillway or be salvaged by PGE biologists (see description of fish salvage in the next paragraph). Flow increases in the Faraday diversion reach—occurring when water formerly diverted to Faraday Lake is instead routed to the diversion reach—would be conducted as gradually as possible to minimize disturbance to fish and other aquatic biota in the diversion reach. PGE proposes to monitor water quality variables during the drawing down of the lake, including turbidity, temperature, dissolved oxygen, pH, and algae, according to the methods described in the Water Quality Monitoring Plan. The plan includes thresholds beyond which PGE would take corrective actions, as well as a schedule for the reporting of monitoring results.

Fish salvage would be conducted as Faraday Lake is drawn down according to an agency-approved Fish Salvage Plan.[9] As the water elevation approaches the bottom of the lake, the release of water would switch from the draft tubes to the spill gates, which are at a slightly lower elevation. As the lake bottom becomes exposed, PGE biologists would look for isolated pockets of water where fish could be trapped. PGE would attempt to capture any fish, using methods to maximize capture and minimize fish injury. All staff working as part of the salvage effort would have the skills needed to ensure the safe handling of fish, especially ESA-listed species. Seines could be used to corral fish, but fish would be dip-netted from the water, placed in containers, and transferred to a fish trailer for transport to Estacada Lake. ESA-listed fish would be kept in water to the maximum extent possible throughout the transfer process.

PGE would obtain necessary federal and state authorizations for conducting fish salvage activities. PGE would coordinate with the Fish Agencies so that their representatives can observe salvage activities. A fish salvage report would be provided to the Fish Agencies within 30 days of completing the salvage operation. The report would include the number of fish removed from the lake, by species; fish release location(s); fish condition at the time of release; and a record of any injury or mortality.

Tailrace Construction Period

To avoid disruption of upstream adult fish passage during the tailrace construction period, water would be flowing through the excavated, low-flow channel, which would provide an area of suitable depths and velocities for adult fish migration during most flows. Based on fish migration timing and associated flow exceedance values during migration periods, there should be few days with elevated velocities during the Chinook and early-run coho migration periods, because flows would be contained within the low-flow channel. Because the upstream migration of these two runs occurs in late spring through fall, these fish should rarely experience flows above 3,000 cfs (1% chance).

[9] The proposed Fish Salvage Plan for Faraday Lake Plan is included in the Application for Non-Capacity Related Amendment of License for the Clackamas River Hydroelectric Project No. 2195 (Project) Part 2 of 4: Exhibit E – Appendix 7, dated March 16, 2018.

Late-run coho and winter steelhead migrate upstream in winter, so they would experience a wider range of baseflows and infrequent floods. At moderate winter baseflows (6,500 cfs), velocities with the cofferdam in place would be slightly elevated compared to existing conditions, but adult fish would have many migration paths with suitable depths and velocities. During floods up to 27,000 cfs, the cofferdam constriction would elevate velocities in the center of the channel compared to existing conditions. However, with the cofferdam in place, there would be a 25- to 35-foot-wide corridor along the north bank where adult salmonids would be able to migrate upstream even under high flows. In addition, these larger rainfall and rain-on-snow peak flow events are typically of short duration (hours to a day), so any velocity-induced adult migration delay is expected to be short. Furthermore, Estacada Lake (which is a short distance downstream of the tailrace) provides abundant deep, low-velocity habitat where adult salmonids would be able hold until floods recede, after which they would be able to resume their upstream migration.

During the tailrace construction period (which is expected to last about 1 year), personnel trained by PGE biologists would conduct visual observations on days that construction activities are taking place to ensure that no adult fish in the vicinity of the construction area are showing signs of delay. Observations made by the trained personnel would be corroborated once per week by PGE biologists. If signs of delay are observed, PGE biologists would be notified immediately, and PGE would notify the Fish Agencies as soon as possible within 24 hours and collaborate with the Fish Agencies to identify appropriate actions to be implemented to minimize the delay.

All work within the area enclosed by the cofferdam would be conducted in the dry. During the construction period, PGE would employ relevant BMPs identified by NMFS in its Biological Opinion for the Clackamas River Project (NMFS 2010), which include erosion control measures for the construction site. As noted previously, hazardous materials removal would be conducted in the dry at the existing powerhouse as required by the ODEQ-approved in condition 2 of the WQC

Water pumped from the tailrace during construction would be routed to a settling basin to allow it to clarify before it is released back to the river channel. Turbidity monitoring would be conducted in the Clackamas River upstream and downstream of the powerhouse during the entire period when construction activities are taking place, as described in the Water Quality Monitoring Plan.

Faraday Lake Refill

When flows are redirected to Faraday Lake following the completion of drawdown-related construction activities, the lake would be refilled at a rate of 0.1 foot/hour. Controlling the rate of flow reintroduction to Faraday Lake would reduce the likelihood of disturbing fine sediments in the lake, which could subsequently be passed downstream and increase turbidity. PGE proposes to monitor water quality variables during reservoir refill, including turbidity, temperature, dissolved oxygen, pH, and algae according to the methods described in the proposed *Water Quality Monitoring Plan*. The plan includes thresholds beyond which PGE would take corrective actions, as well as a schedule for the reporting of monitoring results.

Cofferdam Deconstruction

Deconstruction of the cofferdam would begin with removal of the sheet-pile section. This would be followed by removal of the cellular cofferdam units, beginning downstream and proceeding in an upstream direction. Coarse sediment would be allowed to exit the cellular cofferdam units when the north-side steel frames are lifted. The inner wall of the cellular cofferdam would be kept in place while coarse sediment is being manipulated by machinery on the mid-channel island. Because flows would be low in the Faraday diversion reach during late summer/early fall, most of this work would be completed in the dry. Coarse sediment particles, which would eventually be recruited to the channel, would range in size from 0.25–6.0 inches (i.e., a size that would enhance salmonid spawning/rearing and benthic macroinvertebrate habitat). PGE biologists would conduct weekly reconnaissance to verify that coarse sediment is not impeding upstream adult fish passage. This monitoring would continue until the sediment has been safely mobilized downstream. If passage is impeded, corrective measures would be enacted, in coordination with the Fish Agencies.

To avoid short-term disruption of upstream fish passage during the cofferdam deconstruction period, water would be flowing through the excavated, low-flow channel, which would provide an area of suitable depths and velocities for adult fish. During the deconstruction period, PGE biologists would conduct visual observations each morning to ensure that no fish in the vicinity of the deconstruction area are showing signs of delay. If signs of delay are observed, PGE would notify the Fish Agencies as soon as possible within 24 hours and collaborate with the Fish Agencies to identify appropriate actions to be implemented to minimize the delay.

Because fines would have been removed from the sediment used in the cofferdam units, no significant adverse impacts to downstream water quality are expected when this sediment is released onto the island and subsequently into the channel. PGE would implement an ODEQ-approved Water Quality Monitoring Plan during the deconstruction period, with monitoring protocol and turbidity thresholds at which cofferdam deconstruction would cease and corrective measures would be enacted.

To avoid short-term impacts associated with the operation of heavy equipment, PGE would minimize the amount of time construction equipment enters the river channel. The cellular units would be removed by equipment perched on upstream units. After the coarse sediment is released from the cofferdam units, it would be contoured to facilitate recruitment of sediment to the channel during subsequent high flows. The island is expected to be largely dry during the deconstruction period given the anticipated flows at the expected time of deconstruction (i.e., September 2020), and because Unit 6 would be operating, which would result in most flow being routed around the installation area. In addition, PGE would employ relevant BMPs identified by NMFS in its Biological Opinion for the Clackamas River Project (NMFS 2010 to avoid any effects associated with operating heavy equipment.

Remove Temporary Flow Diversion Berm and Fill Excavated Low-Flow Channel

Following deconstruction of the cofferdam, the temporary flow diversion berm would be removed and the excavated low-flow channel would be filled. To avoid impacts associated with the potential for increased turbidity, PGE would implement an ODEQ-approved Water Quality Monitoring Plan, with monitoring protocol and turbidity thresholds at which activities in the channel would cease and corrective measures would be enacted.

The Clackamas River channel in the vicinity of the powerhouse would be returned to approximately its pre-construction configuration, so that water in the diversion reach flows past the powerhouse outflow, so that fish passing the powerhouse would readily detect the upstream passage route, as they do under existing conditions.

Wildlife Resources

The Proposed Action involves no measures that are expected to affect the pair of bald eagles that has been nesting adjacent to Faraday Lake in recent years (see Section 3.3.4 for more detail). No pile driving would be conducted during the construction of the cofferdam, as explained in Section 2.2.1. Any replaced transmission lines and their supports would be designed to avian-safe standards, including marking the lines with bird flight diversions to reduce bird collisions. Temporarily draining Faraday Lake would have no effect on the eagles, because there are ample feeding opportunities in the immediate vicinity.

Measures Related to Operation of the New Powerhouse

PGE would monitor water quality after the new powerhouse is installed and compare the monitoring results to equivalent data collected under existing conditions. Water quality variables to be monitored would include turbidity, temperature, dissolved oxygen, pH, algae, and total dissolved gas, according to the methods described in the proposed Water Quality Monitoring Plan.

Project-wide downstream fish passage survival and injury standards are outlined in the Clackamas River Project license, Appendix A Article 8(f), Appendix D, articles 23, 24, and 27-31, and Appendix E articles 23, 24, and 27-31. PGE is required by the license to meet or exceed these standards through the implementation of agreed-upon fish passage and protection measures. Failure to meet the standards under a given set of fish passage measures necessitates the implementation of additional measures, as described in appendices D and E of the license. PGE is working with the Clackamas Fish Committee[10] to implement a rigorous program of empirical data collection and fish survival modeling (i.e., using the Downstream Migrant Mortality [DM3] Model) to assess whether conditions are in compliance with the Project-wide standards.

No changes to juvenile fish passage route selection are expected following implementation of the Proposed Action, because the timing and magnitudes of flows entering and exiting Faraday Lake would remain the same as they are under current conditions. Downstream passage studies would be ongoing during and after the implementation of the Proposed Action and would be used to assess patterns of downstream fish passage. As noted previously, empirical fish passage data would be used as input to the DM3 to evaluate smolt survival to assess whether conditions are in compliance with the Project-wide juvenile salmonid passage standards stipulated by the Project license.

At the maximum flow through the new Kaplan turbines (i.e., 900 cfs) water would exit the draft tube at 6.2 feet per second (fps). If both units are operating at maximum flow (1,800 cfs total), the velocity in the river at the downstream end of the new powerhouse would be about 1.3 fps. To evaluate potential adult salmonid mortality in the Faraday Powerhouse tailrace following implementation of the Proposed Action, PGE would conduct surveys of the tailrace during the first three years following completion of the new powerhouse; methods would be the same as those used in the Project area in

[10] The Fish Committee consists of the Licensee; National Marine Fisheries Service (NOAA Fisheries Service); U.S. Fish and Wildlife Service (USFWS); U.S. Forest Service (USDA-FS); Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS); Confederated Tribes of the Grand Ronde Community of Oregon (CTGR); Confederated Tribes of Siletz Indians of Oregon (CTSI); Oregon Department of Fish and Wildlife (ODFW); Oregon Department of Environmental Quality (ODEQ), Clackamas River Basin Council; Association of Northwest Steelheaders; and one representative of the following non-governmental organizations: Trout Unlimited, American Rivers, Oregon Trout, and the Native Fish Society.

2016 (i.e., sampling with an underwater camera once per month from July through October).[11]

The new powerhouse and its appurtenant facilities would be designed to minimize stormwater runoff into the Clackamas River channel. A Post-Construction Stormwater Management Plan is included in the amendment. A final plan would be developed prior to commissioning the new powerhouse, which would ensure that the design and all procedures associated with stormwater management are acceptable to ODEQ.

Proposed Construction Schedule

Table 2. Target schedule for major milestones associated with the Proposed Action.

Project Milestone	**Completion Date**
□□□□□□□□□□ access road to the Clackamas River channel	Apr 2019
Excavate low flow fish passage channel and construct temporary flow diversion berm	May 2019
Construct cofferdam around Faraday Powerhouse tailrace	May 2019
Drawing down of Faraday Lake	Jun 2019
Headworks modifications in Faraday Lake	Jul–Aug 2019
Construction in the tailrace behind the cofferdam	Jul 2019–Aug 2020
Demolition of existing Faraday powerhouse	Aug–Oct 2019
Refill Faraday Lake	Sep 2019
Deconstruct cofferdam around Faraday Powerhouse tailrace	Sep 2020
Remove temporary flow diversion berm and fill in low-flow fish passage channel	Sep 2020
Complete new Faraday Powerhouse structure	Oct 2020
Commission new Faraday Powerhouse	Dec 2020

3.0 ENVIRONMENTAL ANALYSIS

3.1 General Clackamas Project Setting

The Project is located within the Clackamas River Basin, west of the Cascade Range and south of the Columbia River Gorge. The Clackamas River drains more than 940 mi^2 beginning on the slopes of Olallie Butte (elevation 6,000 ft) in the Cascade Mountains, and flows 82.7 miles to its confluence with the Willamette River near

[11] This approach corresponds to that described in the Proposed Study Plan Modification: Plan to Monitor Upstream Fish Passage Effectiveness, approved by FERC on October 22, 2015, 153 FERC ¶ 62,048.

Gladstone and Oregon City. Hydroelectric project operations influence the hydrologic regime of the Clackamas River watershed. Modifications to the natural flow regime include storage in reservoirs, diversions of water from the mainstem, spills over the dams, and powerhouse releases. The Oak Grove Powerhouse, PGE's uppermost development in the basin, discharges into the mainstem Clackamas River, where the combined flow continues downstream to North Fork Reservoir. From there, first North Fork Powerhouse, then Faraday Powerhouse, and lastly River Mill Powerhouse use the combined flow for power generation.

The Clackamas River basin lies within three physiographic regions: High Cascades, Western Cascades, and Willamette Valley. The High Cascades region consists of Quaternary-age (< 2 million year-old) basalt and andesite flows, which have formed the ridges and canyons that confine the Clackamas River. The rivers in this region produce a low sediment yield. Below elevation 3,500 feet to about elevation 300 feet, the Clackamas River runs through the Western Cascades physiographic region. Near the North Fork, Faraday, and River Mill developments, the river has incised into basaltic rocks and created steep canyon walls. The Willamette Valley physiographic region occurs from Estacada to the confluence of the Clackamas and Willamette rivers. This area contains mostly flat-lying sedimentary rocks from as far back as the Pliocene (5.3 - 1.6 million years ago) to as recent as 10,000 years ago.

About 71 percent of the land in the Clackamas River Basin is publicly owned. The upper basin is contained within the Mount Hood National Forest, whereas most of the lands around the lower Clackamas River are privately owned. About 73 percent of the watershed is classified as mature or regrowth forest.

3.2 Scope of Cumulative Effects Analysis

According to the Council on Environmental Quality's regulations for implementing NEPA (40 CFR, section 1508.7), a cumulative effect is the environmental impact that results from the incremental impact of an action when added to other past, present, and reasonably foreseeable future actions, regardless of what agency (federal or non-federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time, including generation of hydroelectric power and other land and water development activities. Based on Commission staff's assessment of the Proposed Action, proposed environmental measures, and agency and public comments, Commission staff concludes that there are no cumulatively affected resources.

3.3 Effects of the Proposed Action

The following sections provide an assessment of the potential environmental effects of the Proposed Action. The affected environment (i.e., the baseline against which the Commission measures effects) is described for each resource area. This is followed by a discussion and analysis of potential resource impacts.

3.3.1. Geology and Soils

Affected Environment

Below elevation 3,500 feet to about elevation 300 feet, the Clackamas River runs through the Western Cascades physiographic region. This region includes an older, inactive volcanic chain with associated deeply weathered rocks that date from 45 to 10 million years ago. It also contains Columbia River Basalt, which originated in lava flows of the Miocene age (16 to 15 million years ago). The river has incised into basaltic rocks and created steep canyon walls near the Faraday Development. The topography is steep in these sections, but has gentler slopes in areas where erosion processes include high sediment-yield earth and debris flows.

Effects of Proposed Action

Excavation and construction associated with the new Faraday Powerhouse would occur within an area composed primarily of engineered fill, although some excavation of bedrock would occur to accommodate the new turbine units. Construction-related BMPs would be implemented to contain all soils and sediments within the construction area. As a result, there would be no significant construction-related impacts on geology and soils due to the Proposed Action.

3.3.2. Water Resources

Affected Environment

The U.S. Geological Survey (USGS) operates the Clackamas River at Estacada gaging station (gage no. 14-210000) located immediately downstream of River Mill Dam. Streamflows at the Estacada gaging station are considered to be representative of those immediately downstream of the Faraday Powerhouse, which is located approximately 2.9 miles upstream of the gaging station. The gage has a drainage area of 681 mi^2 (USGS 2017) and has been operated continuously since 1908. The Faraday Powerhouse has a drainage area of 673 mi^2 (USGS 2017), representing a 1.2 percent difference in total watershed area between the Faraday Powerhouse and the USGS gaging station.

Annual water yield was computed from USGS daily average discharge records at the Estacada gage for the 1908-1999 period, and then classified into five different water-year types based on the frequency distribution of the annual yield. Water yields were ranked and plotted as an exceedance probability, then divided symmetrically into five equally weighted classes separated by annual exceedance probabilities (p) of 0.20, 0.40, 0.60, and 0.80. The five classes were named “Extremely Wet” (p = 0 to 0.20), “Wet” (p = 0.20 to 0.40) “Normal” (p = 0.40 to 0.60), “Dry” (p = 0.60 to 0.80), and “Critically Dry” (p = 0.80 to 1.00). This classification system addresses the range of variability in the annual water yield, assigns water year classes symmetrically around the median water year, and assigns an equal probability for each class that a given water year would fall into that category. Using the entire 91-year period (1908-1999) of USGS daily average streamflow records at the Estacada gage, the following monthly streamflow statistics were computed:

- Highest monthly mean flow: 11,170 cfs; December 1965.
- Highest mean annual flow: 4,407 cfs; 1974.
- Lowest monthly mean flow: 613 cfs; September 1994.
- Lowest mean annual flow: 1,454 cfs; 1977.

PGE completed a water quality assessment of Faraday Lake and the Faraday Diversion Reach, which included both collection of empirical data and water quality modeling using CE-QUAL-W2 (Doughty 2004a; Doughty 2004b; EES Consulting 2004; Battelle 2004). Water quality variables measured or sampled included temperature, dissolved oxygen, pH, hardness, alkalinity, conductivity, nutrients, chlorophyll a, turbidity, total suspended solids, and total dissolved solids. The assessment showed that water quality in these areas complies with ODEQ’s surface water criteria throughout the year.

As required by the Project license, PGE completed channelization of Faraday Lake in fall 2012, and 2013 was the first year of the planned seasonal drawdown of Faraday Lake (i.e., the drawdown needed to ensure that flow passes through the channelized portion of the lake). Each year, PGE conducts a required 1.5-foot drawdown of the lake over the last week of June to reach a water surface elevation of 520 feet on July 1. The lake's surface elevation is held between 519 and 520 feet until PGE returns the lake to its normal operating level (about 521.5 feet) on October 1. Because of the short residence time of water in Faraday Lake during summer, the reservoir does not thermally stratify,

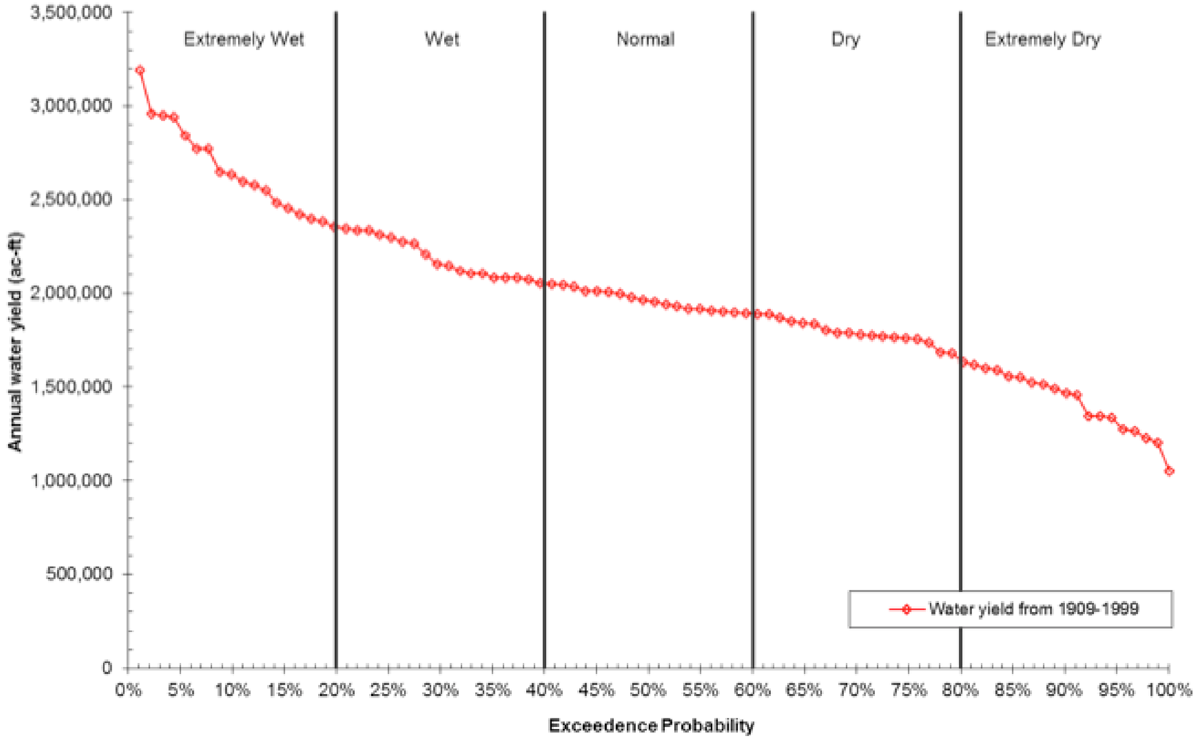

Figure 1. Water yield cumulative distribution curve for the Clackamas River at Estacada gaging station (USGS gage no. 14-210000), 1908-1999.

The berms that contain the channelized portion of the lake are equipped with flow scoops that allow a small volume of water from the channel to enter the impounded sections of the lake on the north and south sides of the channel, which helps maintain water quality in the areas outside the channel.

The results of temperature monitoring conducted during 2016 in Faraday Lake, in the Faraday Diversion Reach upstream of the Faraday Powerhouse, and immediately downstream of the Faraday Powerhouse are shown in Table 3.

Table 3. Monthly averages of daily maximum water temperatures, in Faraday Lake (FAR01), in the Faraday Diversion Reach just upstream of the Faraday Powerhouse (FAR02), and just downstream of the Faraday Powerhouse (FAR03) from June-September 2016.

	Monthly Average of Daily Maximum Temperature (°C)			
Site	**June**	**July**	**August**	**September**
FAR01	14.66	16.47	17.30	13.48
FAR02	15.32	17.44	18.25	--
FAR03	14.68	16.75	17.70	--

-- Average could not be calculated due to malfunction or loss of temperature logger.

Effects of Proposed Action

Construction

Construction of the new Faraday Powerhouse could have minor short-term water quantity effects as a result of the Faraday Lake drawdown and refill. PGE would mitigate potential short-term incremental construction effects on water quality by implementing the construction-related BMPs to control erosion, minimize ground disturbance and prevent effects on aquatic biota. Construction activities would be conducted to meet or exceed all performance standards contained in applicable state and federal permits. When more than one standard applies to the construction action, PGE would adopt the most resource-protective standard.

BMP's to employed during construction are described in detail in Appendix 6 to the application and include: pre-construction measures; erosion control measures such as silt fences, straw bales, and aggregate; avoidance of herbicides unless authorized; minimize disturbance of the streambanks and existing riparian vegetation during construction activities; maintenance of a 150 foot buffer from the edge of the stream bank; measures to be implemented prior to high flow events; treatment of all discharge water created by construction activities; turbidity monitoring; avoidance of pollution discharge within the mean high water mark or 10-year flood plain. The BMP also include measures to avoid or minimize effects for the access road construction, vehicle refueling and maintenance,

As noted previously, the majority of demolition of existing structures would occur above the ordinary high waterline. Any work conducted below the waterline would be performed behind a cofferdam to prevent any material from entering the river. All hazardous materials removal at the existing powerhouse would be conducted per the ODEQ-approved Contaminated Media Management Plan.[12]

Drawdown of Faraday Lake to enable construction would be conducted at a rate of approximately 0.1 foot/hour (see Section 2.2.3) to minimize the potential for pulses of turbidity to be released from Faraday Lake to the powerhouse tailrace. Water temperature would likely decrease and DO would likely increase downstream of Faraday Powerhouse relative to existing conditions during the period when the lake is fully drawn down. Water passed through the diversion reach would have a slightly shorter residence time than what would occur if water were routed through the lake, thereby resulting in slightly less warming. Similarly, DO in the river would likely increase because the lower water temperatures and increased turbulence in the diversion reach (relative to Faraday Lake) would lead to greater oxygenation. When flows are redirected to Faraday Lake following the completion of construction activities in the Faraday Lake forebay, the lake would be refilled at a rate of 0.1 foot/hour.

Water quality monitoring would be conducted during the drawing down and refill of Faraday Lake and during construction-related activities. PGE would monitor water temperature, dissolved oxygen, pH, turbidity, and algae at designated locations and times, and take corrective actions if water quality impacts surpass identified thresholds, as described in the Water Quality Monitoring Plan.

Operation

Following construction of the new Faraday Powerhouse, PGE would remain in compliance with its approved *Water Quality Management and Monitoring Plan* for the Project (PGE 2015). Faraday Lake water levels and flow requirements downstream of the Faraday Powerhouse would remain as they are under existing conditions (see Section 2.1.2), and as a result there would be no incremental effects on temperature, DO, total dissolved gas, pH, or any other water quality variables. Faraday Lake would continue to be partially drawn down in summer, as it is under current protocol, with water largely contained within the channelized portion of the lake during that period. Water quality monitoring would be conducted when the new powerhouse comes on line (i.e., after all construction-related activities are completed). PGE would monitor water temperature, dissolved oxygen, pH, turbidity, algae, and total dissolved gas and compare monitoring results to baseline data collected prior to the implementation of the Proposed Action, as described in the Water Quality Monitoring Plan. We conclude that there would be little to no long-term effect on water quality in the Clackamas River.

[12] Application for Non-Capacity Related Amendment of License (Application) for the Clackamas River Hydroelectric Project No. 2195 (Project) Part 3 of 4: Exhibit E – Appendix 1, dated March 16, 2018.

3.3.3. Fish and Aquatic Resources

Affected Environment

The Clackamas River Basin is an important producer of anadromous fish within the Mount Hood National Forest, providing 142 miles of anadromous fish habitat (Stillwater Sciences 1999). The basin also supports substantial resident fish populations and is heavily used by recreational anglers targeting both anadromous and resident fish species. The Clackamas River from the Faraday Diversion Dam downstream to the Faraday Powerhouse supports cutthroat trout, rainbow trout, steelhead, coho salmon, spring Chinook salmon, and Pacific lamprey, as well as occasional fall Chinook salmon, bull trout, and other resident species. Coho, Chinook, and steelhead are currently listed as threatened under the Endangered Species Act (ESA) (see Section 3.3.5). The bull trout, which is also a threatened species, belong to a non-essential experimental population first translocated to the Clackamas River basin in 2011.

Faraday Lake contains juvenile anadromous Chinook, steelhead, and coho. These fish have passed over the North Fork Dam spillway or through the North Fork Powerhouse and then subsequently entered Faraday Lake. The overwhelming majority of juvenile anadromous salmonids produced in the upper Clackamas River basin are bypassed around the Project area via two surface collection systems in the North Fork Dam forebay. Faraday Lake is also stocked annually by ODFW with catchable-sized rainbow trout.

Aquatic Biology Associates and Framatome-ANP DE&S (2002) found that river margin habitat in the mainstem dam tailraces and Faraday Diversion Reach supports high densities of benthic macroinvertebrates. Cool-water releases in the Project area appear to extend the distribution of intolerant taxa (i.e., indicators of good water quality) farther downstream through the Project area than would likely occur under natural conditions.

<u>Adult Salmonid Upstream Passage</u>

There is an existing a 1.9-mile-long fish ladder extending from immediately downstream of the Faraday diversion dam upstream to North Fork reservoir.

The best indicator of the number of adult salmon and steelhead passing through the reach adjacent to the Faraday Powerhouse is provided by counts at the North Fork adult sorting facility. Some fish entering the reach near the powerhouse do not arrive at the adult sorting facility; they may spawn in the Faraday Diversion reach, be caught by anglers, or die. However, the number of fish that do not arrive at the sorting facility is relatively small compared to those that do arrive (Ackerman et al. 2015; David et al. 2017), so counts at the sorting facility provide a valuable and reasonably accurate estimate of passage through the reach adjacent to Faraday Powerhouse.

The mean return (2010–2017) of unmarked Chinook to the North Fork adult sorting facility has been 2,210 (range 984–3,586), with an additional 1,755 (range 205–3,503) marked (hatchery) individuals. The unmarked fish represent a mix of UWR Chinook and LCR Chinook. A large majority of the Chinook that pass through the North Fork adult sorting facility each year are UWR Chinook, though it is believed based on external characteristics of the fish, that some Chinook (estimated to typically be <150 per year) are fall run (LCR Chinook). Chinook passage at the adult sorting facility begins in early May and concludes around late October, with a median passage date since 2013 of July 15. Estimated residency times for adult Chinook in the Faraday Powerhouse tailrace area are shown in Table 4.

Since 2010, the mean return of unmarked Lower Columbia River (LCR) coho to the North Fork adult sorting facility has been 3,098 (range = 1,207–8,244). Very few marked coho arrive at the sorting facility, with an annual average return of four hatchery fish since 2010 (maximum = 12). Coho passage at the adult sorting facility begins in late August and concludes in early February, with a median passage date since 2013 of October 1. Estimated residency times for adult LCR coho in the Faraday Powerhouse tailrace area are shown in Table 4.

The mean return of LCR steelhead to the adult sorting facility for the period of 2010-2017 has been 1,475 (range 870–2,311). Marked hatchery fish returns over the same period have averaged 451 fish (range 94–862). Winter steelhead passage at the adult sorting facility begins in December and concludes in mid June, with a median passage date since 2013 of April 6. Estimated residency times for adult LCR steelhead in the Faraday Powerhouse tailrace area are shown in Table 4.

Table 4. Estimated residency times in the Faraday Powerhouse tailrace for radio-tagged adult salmon and steelhead. The tailrace antenna array detects fish approximately 1,000 ft upstream and downstream of the tailrace. Estimates derived from Ackerman et al., 2014; David et al., 2017; and David et al., (in prep.).

			Days			
Species	**Year**	**Count**	**Min**	**Median**	**Mean**	**Max**
Steelhead	2014	41	0.03	0.37	1.34	8.92
	2016	48	0.04	0.84	2.23	16.76
Chinook	2014	51	0.00	1.23	5.80	71.34
	2016	48	0.02	0.56	1.25	7.87
	2017	17	0.03	0.08	1.01	6.35
Coho	2014	48	0.03	0.34	0.90	6.65
	2016	45	0.02	0.40	1.00	7.00

Juvenile Usage

Juvenile Chinook, steelhead, and coho may be present in the reach adjacent to the Faraday Powerhouse during any time of the year. Limited spawning occurs within and just upstream of the area, and some juveniles may also enter the area after passing North Fork Dam via the spillway or through the turbines. However, the vast majority of juvenile anadromous salmonids from the upper basin are collected by PGE's downstream passage facilities in the North Fork forebay and bypassed around the Faraday diversion reach. Also, most fish produced downstream of the Faraday Diversion Dam originate below the Faraday Powerhouse and tend to move into Estacada Lake to find rearing habitat.

The times when juvenile salmonids are most likely to occur in the reach adjacent to the Faraday Powerhouse are coincident with downstream migration periods from the upper Clackamas River basin. This timing is best indexed by fish collection rates in the North Fork juvenile bypass system (Table 5).

Table 5. Timing (percentage) of downstream migrants passing through the North Fork juvenile bypass system, by month and species, for 2011-2017; cells representing > 5% are highlighted.

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chinook	3	3	1	8	12	4	4	3	4	23	29	7
Steelhead	1	1	2	28	52	4	1	0	0	3	5	2
Coho	2	1	2	4	43	25	2	0	0	2	16	3
Avg. Spill Days	4	4	7	3	2	0	0	0	0	1	3	6

Effects of the Proposed Action

Construction

To avoid having impacts on fish and aquatic resources during the construction of the new Faraday Powerhouse, PGE proposes to implement a number of environmental measures, which are described in greater detail in Section 2.2.3. A temporary low-flow fish passage channel would be excavated, and a flow diversion berm would be constructed to direct water into the low-flow channel. Together these features would provide a passage route for fish during the construction period. Hydraulic modeling was used to inform the design of the low-flow channel so that it provides velocities and depths (which were identified in collaboration with the Fish Agencies) that would be conducive to upstream fish passage under a range of common flows. When the construction period comes to an end, the flow diversion berm would be removed, and the low-flow channel would be filled in so that river flow once again passes along the south side of the channel so that river flow can easily be detected by adult salmonids in the vicinity of the powerhouse.

To avoid short-term impacts due to heavy equipment operating near and within the channel, PGE would employ relevant BMPs identified by NMFS in its Biological Opinion for the Clackamas River Project (NMFS 2010). Moreover, most construction would be conducted in the dry behind a cofferdam (see Sections 2.2.1, 2.2.3). During construction and deconstruction of the cofferdam, equipment would come into minimal contact with the river channel, as much of the work would be accomplished by equipment perched on the top of the cofferdam. As noted previously, hazardous materials removal would be conducted in the dry at the existing powerhouse per condition 2 of the WQC requiring implementation of the Contaminated Media Management Plan filed with the amendment application.

Noise associated with the installation of the cellular cofferdam is expected to be well below the 150 dBRMS threshold for fish behavioral effects identified by the Washington State Department of Transportation (WSDOT)[13]. To avoid short-term disturbance to or injury of salmonids resulting from loud noise during installation of the sheet-pile portion of the cofferdam, PGE would use divers or a barge-mounted drill rig to bore into the bedrock and set the piles with grout. The drill slurry and rock powder would be pumped to the surface and stored in a tank for subsequent disposal. No slurry would be released into the river. PGE would use a bubble curtain to keep fish out of the area where the drilling is taking place. Grout would be isolated from the water column until it is cured.

Deconstruction of the cofferdam would result in liberation of the coarse sediment used to fill the cellular cofferdam units. Sediment particles would range in size from 0.25–6.0 inches, (i.e., a size that would enhance salmonid spawning and rearing habitat and benthic macroinvertebrate habitat). Because fines would have been removed from the sediment, no adverse impacts to downstream water quality are expected when this sediment is released onto the island and into the channel. After the coarse sediment is released from the cofferdam units, it would be spread out on the island, and the sediment pile would be contoured to facilitate recruitment of sediment to the channel during subsequent high flows.

To avoid impacts associated with potential turbidity pulses, PGE would implement an ODEQ-approved Water Quality Monitoring Plan throughout the construction period.

[13] Biological Assessment Preparation for Transportation Projects - Advanced Training Manual, Chapter 7, Noise Impact Assessment, January 2018

https://www.wsdot.wa.gov/Environment/Biology/BA/BAguidance.htm#Manual

The plan contains monitoring protocol and turbidity thresholds at which excavation activities would cease and corrective measures would be enacted.

Throughout the construction process, PGE biologists would observe fish presence and behavior to avoid impacts on juvenile or adult fish and ensure that fish passage is unimpeded (see Section 2.2.3 for greater detail on when and how observations and protective measures would be implemented). To avoid disruption of upstream adult fish passage during the tailrace construction period, water would be flowing through the excavated, low-flow channel, which would provide an area of suitable depths and velocities for adult fish migration during most flows. Based on the migration timing and associated flow exceedance values during those migration periods, there should be few days with elevated velocities during Chinook and early-run coho migration periods because flows would be contained within the low-flow channel. Because the upstream migration of these two runs occurs in late spring through fall, these fish should rarely experience flows above 3,000 cfs (1% chance). Late-run coho and winter steelhead migrate upstream in winter, so they would experience a wider range of baseflows and infrequent higher magnitude floods. At moderate winter baseflows (6,500 cfs), velocities would be slightly elevated compared to existing conditions, but adult fish would have many migration paths with suitable depths and velocities. During floods up to 27,000 cfs, the cofferdam constriction would elevate velocities in the center of the channel compared to existing conditions. However, with the cofferdam in place, there would be a 25- to 35-foot-wide corridor along the north bank where adult salmonids would be able to migrate upstream. In addition, these larger rainfall and rain-on-snow peak flow events are typically of short duration (hours to a day), so any velocity-induced adult migration delay is expected to be short. Furthermore, Estacada Lake provides abundant deep, low velocity habitat where adult salmonids can hold until the flood peak recedes, after which they would be able to resume their upstream migration.

To minimize fish stranding and turbidity during the draining of Faraday Lake, water surface elevation would be lowered at a rate of approximately 0.1 foot/hour. This drawdown rate is expected to allow fish, including juvenile Pacific lamprey, to follow the declining water level to the downstream end of Faraday Lake, where they would either exit the lake through the powerhouse/spillway or be salvaged by PGE biologists. PGE proposes to monitor water quality variables during reservoir drawdown, including turbidity, temperature, dissolved oxygen, pH, and algae according to the methods described in the proposed Water Quality Monitoring Plan. The plan includes thresholds beyond which PGE would take corrective actions, as well as a schedule for the reporting of monitoring results.

When flows are redirected to Faraday Lake following the completion of construction activities in the forebay, the lake would be refilled at a rate of 0.1 foot/hour. Controlling the rate of flow reintroduction to Faraday Lake would reduce the likelihood of disturbing fine sediments in the lake, which could subsequently be passed downstream and increase turbidity. PGE proposes to monitor water quality variables during reservoir refill, including turbidity, temperature, dissolved oxygen, pH, and algae according to the methods described in the proposed Water Quality Monitoring Plan. Again, the plan includes thresholds beyond which PGE would take corrective actions, as well as a schedule for the reporting of monitoring results.

Operation

Fish Passage

No false attraction to the existing Faraday Powerhouse has been observed, and no change is expected because the new powerhouse would operate according to the requirements of the existing license. Radio-telemetry and PIT tagging would be used to verify that migration of adult salmonids past the powerhouse has not changed following the implementation of the Proposed Action. To accomplish this, the Upstream Passage Effectiveness Study, which is expected to be completed in 2019, would be extended into 2021 and 2022, with 2021 being a pulse-flow[14] year and 2022 being a non-pulse flow year. Upstream effectiveness tagging scheduled for 2018-2019 would be postponed until after completion of the construction associated with the Proposed Action.

No changes to juvenile fish passage route selection are expected following implementation of the Proposed Action, because the timing and magnitudes of flows entering and exiting Faraday Lake would remain the same as they are under current conditions. Downstream passage studies would be ongoing during and after the implementation of the Proposed Action and would be used to assess patterns of downstream fish passage. As noted previously, empirical fish passage data would be used as input to the DM3 to evaluate smolt survival to assess whether conditions are in compliance with the Project-wide juvenile salmonid passage standards stipulated by the Project license.

At the maximum flow through the new Kaplan turbines (i.e., 900 cfs) water would exit the draft tube at 6.2 fps. If both units are operating at maximum flow (1,800 cfs total), the velocity in the river at the downstream end of the new powerhouse would be about 1.3 fps. To evaluate potential adult salmonid mortality in the Faraday Powerhouse tailrace following implementation of the Proposed Action, PGE would conduct surveys of the tailrace during the first three years following completion of the new powerhouse;

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[14] PGE is conducting a FERC-approved series of evaluations to assess the response of spring Chinook to pulsed flows in the mainstem Clackamas River Project area, 139 FERC ¶ 62,267.

methods would be the same as those used in the Project area in 2016 (i.e., sampling with an underwater camera once per month from July through October).[15]

If PGE fails to meet the Project-wide survival standards, more intense scrutiny of individual facilities, including Faraday Lake and Powerhouse, would take place in a manner considered appropriate by the Fish Committee and approved by the Fish Agencies in the context of compliance with the exiting Project license. This could involve juvenile salmonid tagging studies focused solely on the Faraday Development. However, most juvenile salmonids from the upper Clackamas River basin are captured in North Fork Reservoir and passed to the River Mill Dam tailrace through the downstream migrant pipeline. Therefore, it is unlikely that the small number of fish that could pass through Faraday Lake would have a significant effect on the Project-wide survival standard.

Turbine Mortality

The vertical Kaplan turbines selected for the new powerhouse are expected to improve fish survival and reduce fish injury rates when compared to the existing units. Conditions are expected to improve for several reasons. The new units would be more efficient, with tighter clearances and fewer gaps in which fish could become lodged or injured. The new turbine blades have better hydraulic profiles and are smoother, which helps to reduce cavitation and fish mortality. The configuration of the existing duplex horizontal units requires water to follow a convoluted path and involves two opposing runners discharging into a common header. This results in a large amount of churning and turbulence throughout the turbine. The proposed vertical turbines would create a more streamlined flow path, which along with the new draft tube arrangement would produce less turbulence, and as a result less fish disorientation. Replacing the five original units with two physically larger units would result in lower water velocities in the new units. The larger units would also have larger openings (i.e., blade spacing) than the existing turbine runner vents (i.e., spacing between the buckets), which could safely pass larger fish than the existing units.

PGE would continue to use the agreed-upon, existing turbine mortality rate for the DM3. Because the new units would improve passage conditions for juvenile fish, use of the existing turbine mortality rate would be conservative from a resource-protection standpoint (i.e., it would likely overestimate fish mortality associated with operating the new turbines). If in the future it appears that mortality at Faraday Powerhouse is sufficient to influence the Project-wide survival standard (as revealed by application of

[15] This approach corresponds to that described in the Proposed Study Plan Modification: Plan to Monitor Upstream Fish Passage Effectiveness, approved by FERC on October 22, 2015, 153 FERC ¶ 62,048.

the DM3), PGE would consult with the Fish Committee to develop any studies needed to better understand turbine mortality.

3.3.4. Wetland, Wildlife, and Botanical Resources

Affected Environment

The Faraday Powerhouse is located within an existing, disturbed area dedicated primarily to the generation of hydroelectric power. There are no wetlands or significant botanical resources within the proposed footprint for construction activities associated with the Proposed Action. Per email correspondence with PGE on February 23, 2018, the USFWS determined that no species of concern (beside the bull trout addressed in Section 3.3.5) are present in this area.

In recent years, a pair of bald eagles has been nesting adjacent to Faraday Lake upstream of the powerhouse. The nest is located on PGE property on the south shore of Faraday Lake, approximately 0.3 miles (≈ 1,580 ft) from the Faraday Lake Dam intake structure.

Effects of the Proposed Action

To the extent practicable, PGE would minimize loud noises within the 0.5-mile buffer around the nest from January 1 through August 31 (if the eagles do not nest during 2019–2020 noise would not be an issue relative to this species). PGE biologists would brief construction crews on the importance of, and how to go about, minimizing disturbances to the eagles. The temporary drainage of Faraday Lake to accommodate construction in the forebay would have no adverse effect on the eagles, because ample feeding opportunities exist nearby in the mainstem Clackamas River, Estacada Lake, and North Fork Reservoir. Any replaced transmission lines and their supports would be designed to avian-safe standards, including marking the lines with bird flight diversions to reduce bird collisions.

Because operation of the powerhouse following completion of the Proposed Action would be the same as it is under existing conditions, there would be no incremental effects of powerhouse operations on wetlands, wildlife, or plants.

3.3.5. Threatened, Endangered, and Sensitive Species

Affected Environment

ESA-listed species that occur in the vicinity of the Faraday Development are shown in Table 6.

Table 6. Federally listed species that occur in the vicinity of the Faraday Development.

ESU/DPS	Scientific Name	Listing Status
Upper Willamette River Chinook Salmon ESU	*Oncorhynchus tshawytscha*	Threatened
Lower Columbia River Chinook Salmon ESU	*O. tshawytscha*	Threatened
Lower Columbia River Coho Salmon ESU	*O. kisutch*	Threatened
Lower Columbia River Steelhead DPS	*O. mykiss*	Threatened
Bull trout[1]	*Salvelinus confluentus*	Threatened

[1] Bull trout in the Clackamas River basin constitute a Nonessential Experimental Population.

Per email correspondence with PGE dated February 23, 2018, the USFWS determined that no ESA-listed species under USFWS jurisdiction, beside bull trout, are present in the area that would be affected by the Proposed Action. Because of its non-essential experimental population status, no ESA Section 7 consultation is required with the USFWS for bull trout in the Clackamas River basin.

Effects of the Proposed Action

As described in Section 3.3.3, no adverse impacts on threatened fish species are anticipated as the result of the Proposed Action. Short-term potential impacts associated with construction would be mitigated as described in Sections 2.2.3 and 3.3.3, and operation of the new Faraday Powerhouse would be the same as it is under existing conditions, so no long-term impacts would occur. For the same reasons, there would be no adverse effects on bull trout as the result of implementing the Proposed Action.

3.3.6. Recreational Resources and Land Use

PGE owns all the land associated with the Faraday Powerhouse and its access routes. The Faraday Development provides land-based, day-use recreational opportunities, primarily bank fishing at Faraday Lake. No boating or overnight uses occur adjacent to Faraday Lake. The Faraday diversion reach is only accessible from a closed road off Highway 224, which is used primarily by hikers, cyclists, and whitewater boaters, or via a trail from Faraday Lake. One guidebook rates the diversion reach as Class II-III whitewater at relatively low flows, but interviews with paddlers after a flow test several years ago suggested that the reach is Class III-IV at flows in the range of 600 to 1,200 cfs, and probably has Class V rapids at very high flows.

Effects of Proposed Action

Construction

As noted previously, implementation of the Proposed Action would require Faraday Lake to be drained completely. The lake may be dewatered for as long as 3-4 months (i.e., June–September 2019). PGE plans to eliminate access to lands surrounding Faraday Lake during 2019–2020 to ensure the safety of the public. Angling would again be possible after Faraday Lake is refilled and public access is restored, but fish numbers would remain low until ODFW restocks the lake.

Operation

There would be no incremental effects on recreation in Faraday Lake or the Faraday diversion reach as the result of operating the new powerhouse. Faraday Powerhouse would continue to be operated as it is under existing conditions, and access to Faraday Lake would be restored following implementation of the Proposed Action.

In addition, in a January 30, 2019 filing, PGE notified the Commission that it plans to close access to Faraday Lake; including the Faraday Lake Recreation Area, in order to safely manage construction activities. The closure would commence on March 1, 2019 and the licensee expects it to last through the end of 2020. PGE says it has installed a sign at the site to notify the recreating public of the planned closure. In addition, PGE also announced the closure on its website and intends to put an announcement in the local newspaper, the Estacada News. PGE says it would inform the public of alternative locations for nearby hiking and fishing opportunities in the newspaper announcement.

3.3.7. Aesthetic Resources

Affected Environment

The Faraday Development is located in a narrow, forested canyon. The Faraday Diversion Dam is not visible from Highway 224, so relatively few people see this facility. The Faraday diversion reach consists of a winding scenic gorge, which is visible from the bridge (limited to pedestrians and service vehicles) across the Clackamas River that links the parking area with the recreation areas at Faraday Lake. Faraday Lake is set relatively high above the river and constructed with an embankment against a forested hillside. The penstocks, powerhouse, and a substation are located at the toe of the embankment and are not easily visible from the recreation areas above or from Highway 224.

Effects of Proposed Action

There would be no significant effects on aesthetic resources due to implementation of the Proposed Action. Given the already heavily developed nature of the Clackamas River in the vicinity of the Faraday Development, there would be no incremental aesthetic effect associated with the construction or operation of the new powerhouse.

3.3.8. Cultural Resources

Definition of Cultural Resources, Historic Properties, Effects, and Area of Potential Effects

Historic properties are cultural resources listed or eligible for listing in the National Register. Historic properties can be buildings, structures, or objects, districts (a term that includes historic and cultural landscapes), or sites (archaeological sites or locations of important events). Historic properties also may be resources of traditional religious and cultural importance to any living community; such as an Indian tribe or a local ethnic group, that meet the National Register criteria; these properties are known as traditional cultural properties. Cultural resources must possess sufficient physical and contextual integrity to be considered historic properties. For example, dilapidated structures or heavily distributed archaeological sites, although they may retain certain historical or cultural values, may not have enough integrity to be considered eligible.

Section 106 of the NHPA requires the Commission to evaluate potential effects on properties listed or eligible for listing the National Register prior to an undertaking. An undertaking means a project, activity, or program funded in whole or in part under the direct or indirect jurisdiction of a federal agency, including, among other things, processes requiring a federal permit, license or approval. Advisory Council on Historic Preservation (Advisory Council) regulations implementing section 106 define effects on historic properties as those that change characteristics that qualify those properties for inclusion for the National Register. In this case, the undertaking is the removal of the historic Faraday powerhouse and associated facilities, which are contributing resources to the Clackamas Hydroelectric Project, which is eligible for the National Register.

Determination of effects on historic properties first requires identification of any historic properties in the APE. The Advisory Council's regulations define the APE as "the geographic area or areas within which an undertaking may directly or indirectly cause alterations in the character or use of historic properties, if any such properties exist.[16] For this undertaking, the APE includes lands within the project boundary as well as lands outside of the project boundary where project construction and/or operation may

[16] 36 C.F.R. Section 800.16(d).

affect historic properties. The APE includes all access roads, laydown areas, and other locations required during construction and a 100-foot buffer around these areas.

Effects on cultural resources within the APE can result from project-related activities such as reservoir operations, modifications to project facilities, or project related ground-disturbing activities. Effects also can result from other forces such as wind and water erosion, recreational use (project and non-project related), vandalism, and private and commercial development. In the case of the licensee's proposal to amend the Clackamas Hydroelectric Project's license, PGE consulted with the Oregon State Historic Preservation Office (Oregon SHPO) to develop a Memorandum of Agreement (MOA) that identifies appropriate mitigation measures for these adverse impacts. PGE proposes to implement the following mitigation measures, which are described in detail in the MOA: (1) provide State of Oregon documentation of the Faraday Powerhouse and related resources; (2) publish Faraday/Clackamas Project content using the Next Exit History application; (3) fund the digitization of multiple historic newspapers; (4) identify and interview people familiar with the operation of the Faraday Powerhouse to gather stories and personal histories of the plant; (5) plan and host a social gathering to be held at the powerhouse; (6) install a camera above the powerhouse site to provide time-lapse video of the powerhouse demolition and construction, which would be available on the internet; and (7) to the extent feasible, identify appropriate elements of the Faraday Powerhouse and related buildings for salvage and retention for interpretation/recreational use at the Faraday Dam Recreational Area. To manage potential impacts on cultural resources during the construction period, PGE and its subcontractors would follow PGE's Inadvertent Discovery Protocol. This Protocol is included as Appendix D to the Project's Historic Properties Management Plan. However, given that all work would take place in a previously developed location, it is extremely unlikely that archeological resources would be encountered during construction.

Construction of the Cazadero Diversion Dam (subsequently replaced with the Faraday Diversion Dam) and Faraday Powerhouse began in 1902 and was completed in 1907. The historic built resources of the Faraday Lake Dam and Powerhouse have been determined to be eligible for inclusion in the NRHP. The proposed location of construction was subjected to an intensive, systematic cultural resources survey during the relicensing of the Clackamas River Project, and no archaeological sites were documented within the proposed footprint for the Proposed Action (Oetting 2004). Because the area has been heavily disturbed by previous activities, the inadvertent discovery of cultural material is unlikely.

Effects of Proposed Action

The historic built resources of the Faraday Lake Dam and Powerhouse have been determined to be eligible for inclusion in the NRHP. A finding of effect analysis indicated that implementing the Proposed Action would result in adverse impacts on historic resources. PGE consulted with the Oregon SHPO to develop a MOA that identifies appropriate mitigation measures for these adverse impacts. PGE proposes to implement the following mitigation measures, which are described in detail in the MOA: (1) provide State of Oregon documentation of the Faraday Powerhouse and related resources; (2) publish Faraday/Clackamas Project content using the Next Exit History application; (3) fund the digitization of multiple historic newspapers; (4) identify and interview people familiar with the operation of the Faraday Powerhouse to gather stories and personal histories of the plant; (5) plan and host a social gathering to be held at the powerhouse; (6) install a camera above the powerhouse site to provide time-lapse video of the powerhouse demolition and construction, which would be available on the internet; and (7) to the extent feasible, identify appropriate elements of the Faraday Powerhouse and related buildings for salvage and retention for interpretation/recreational use at the Faraday Dam Recreational Area.

To manage impacts on cultural resources during the construction period, PGE and its subcontractors would follow PGE's Inadvertent Discovery Protocol. However, because the area has been heavily disturbed by previous activities, the inadvertent discovery of cultural material is unlikely.

Once the Proposed Action has been completed, the Faraday Powerhouse would operate as it does under existing conditions. As a result, there is no potential for any incremental effects on cultural resources associated with operation of the new powerhouse.

3.4 No-Action Alternative

Under the No-Action Alternative, the Faraday Powerhouse would not be replaced. By definition, there would be no changes to resources beyond what would occur under baseline conditions. The Faraday Development would generate electricity under the less efficient existing turbine configuration, and PGE would forego (1) implementation of the proposed flood protection and seismic upgrades, (2) the coarse sediment augmentation (i.e., release of material from the cellular cofferdam units), and (3) improved turbine passage survival for the small number of juvenile salmonids that enter Faraday Lake from upstream.

3.5 Unavoidable Adverse Effects

There would be no unavoidable adverse effects due to the implementation of the Proposed Action. PGE has identified a number of measures (identified and described in Sections 2.2.3 and 3.3) to avoid adverse impacts on resource values.

4.0 COMPREHENSIVE DEVELOPMENT AND STAFF RECOMMENDED MEASURES

Sections 4(e) and 10(a) of the FPA require the Commission to give equal consideration to all uses of the waterway on which a project is located. When we review a hydropower project, we consider the water quality, fish and wildlife, recreation, cultural, and other non-developmental values of the involved waterway equally with its electric energy and other developmental values. In deciding whether, and under what conditions a hydropower project should be licensed, the Commission must determine that the project would be best adapted to a comprehensive plan for improving or developing the waterway. This section contains the basis for, and a summary of, our recommendations for conditions to be included in any amendment to the license to: 1) rebuild the Faraday Powerhouse; 2) remove existing turbine units 1 through 5 and replace them with two efficient units; 3) enhance the seismic stability of the powerhouse; and 4) install structures to prevent the powerhouse from flooding during excessive flows.

Based on our independent review and evaluation of the environmental and economic effects of the proposed action and the no-action alternative, we recommend the proposed action as the preferred alternative. We recommend this alternative because: (1) issuing an amendment of the project license would allow the licensee to continue operating the project as a beneficial and dependable source of electric energy; (2) increase the seismic stability of the Faraday Powerhouse and enhance the ability of the powerhouse to resist flooding during high flow events; and (3) the proposed environmental measures identified below would protect project resources.

We recommend including the following environmental measures proposed by PGE in any amended license issued by the Commission for the Clackamas River Project. These recommendations are consistent with the WQC issued by the ODEQ, and NMFS's Biological Opinion

Construction-Related Measures

<u>Water and Aquatic Resources</u>

- Excavate a low-flow, fish passage channel located upstream of the Faraday Powerhouse tailrace and use excavated sediment to construct a temporary flow diversion berm to route water into the excavated channel to provide fish passage during the construction of the new powerhouse.

- Conduct pre-excavation reconnaissance to evaluate the need for fish salvage efforts. If needed, salvage would be conducted using agency-approved and permitted methods (analogous to those described below for the drawing down of Faraday Lake).

- Excavation of the low-flow channel and flow diversion berm would be conducted over a short period, expected to be one day to avoid short-term interference with adult salmonid upstream passage.

- Implement an ODEQ-approved Water Quality Monitoring Plan, with monitoring protocol and turbidity thresholds at which channel excavation activities would cease and corrective measures would be enacted.

- Use heavy equipment operating near and within the channel, would employ best management practices (BMPs) identified in the NMFS Biological Opinion for the Clackamas River Project (NMFS 2010).[17]

Construction of Cofferdam around the Faraday Powerhouse Tailrace

- Conduct pre-excavation reconnaissance to evaluate the need for fish salvage efforts and monitor for fish migration delay at the start of each workday. Any fish salvage would be conducted using agency-approved and permitted methods (analogous to those described below for the drawing down of Faraday Lake). If signs of fish migration delay are observed, PGE would notify the resources agencies as soon as possible within 24 hours and collaborate with the resource agencies to identify appropriate actions to be implemented to minimize the delay.

- Use divers or a barge-mounted drill rig to bore into the bedrock and set the cofferdam piles with grout. Pump drill slurry and rock powder into storage tanks for subsequent disposal.

- Use a bubble curtain to keep fish out of the construction area where the drilling is taking place. Isolated grout from the water column until cured.

- Allow at least 12 hours for any fish within the tailrace behind the cofferdam to exit the area. In the unlikely event, any fish remain in the tailrace area, they would be induced to leave by walking/floating the tailrace area.

- Upon completion of the cofferdam, water would be pumped out of the area. To avoid entrainment of fish, PGE would screen the intakes of the pumps used to dewater the tailrace. Any fish that remain within the cofferdam area would be salvaged using agency-approved and permitted methods (analogous to those described below for the drawing down of Faraday Lake).

[17] *See*: Appendix F, 133 FERC ¶ 62,281 (2010), order on reh'g, 134 FERC ¶ 61,206 (2011)

- Minimize the amount of time construction equipment enters the river channel and employ relevant BMPs, including erosion control measures identified in the 2010 NMFS Biological Opinion for the Clackamas River Project.

Drawing Down Faraday Lake

- To minimize turbidity and fish stranding in Faraday Lake during the construction-related drawdown, lower the water surface elevation of Faraday Lake at a rate of approximately 0.1 foot/hour while limiting the increase in flow in the Faraday diversion reach as gradually as possible to minimize disturbance to fish and other aquatic biota in the diversion reach.

- Monitor water quality variables during the drawing down of the lake, including turbidity, temperature, dissolved oxygen, pH, and algae, according to the methods described in the proposed Water Quality Monitoring Plan filed with the application and implement corrective action if parameters are exceeded.

- Salvage fish during the lake drawn down according to an agency-approved Fish Salvage Plan. In isolated pools where fish could be trapped fish would be captured using methods to maximize capture and minimize fish injury.

- Train workers in the safe handling of fish, especially ESA-listed species using seines to corral fish and dip-nets to transfer fish to containers and fish trailers for transport to Estacada Lake. ESA-listed fish would be kept in water to the maximum extent possible throughout the transfer process.

- Obtain necessary federal and state authorizations for conducting fish salvage activities and coordinate with the resource agencies so that their representatives can observe salvage activities. A fish salvage report would be provided to the Fish Agencies within 30 days of completing the salvage operation. The report would include the number of fish removed from the lake, by species; fish release location(s); fish condition at the time of release; and a record of any injury or mortality.

Tailrace Construction

- During the tailrace construction period conduct visual observations on days that construction activities take place to ensure that no adult fish in the vicinity of the construction area are showing signs of delay. If signs of delay are observed, notify the resource agencies as soon as possible within 24 hours and collaborate with the agencies to identify appropriate actions to be implemented to minimize the delay.

- Conduct work within the cofferdam in the dry and employ relevant BMPs identified in the 2010 NMFS in its Biological Opinion for the Clackamas River Project.

- Hazardous materials removal would be conducted in the dry at the existing powerhouse according to the proposed Contaminated Media Management Plan.

- Water pumped from the tailrace during construction would be routed to a settling basin to allow it to clarify before it is released back to the river channel.

Faraday Lake Refill

- Following the completion of drawdown-related construction activities, refill Faraday Lake at a rate of 0.1 foot/hour to minimize fine sediment disturbance.

Cofferdam Deconstruction

- Begin deconstruction of the cofferdam by removing the sheet-pile section, followed by removal of the cellular cofferdam units, beginning downstream and proceeding in an upstream direction allowing coarse sediment to exit the cellular cofferdam units when the north-side steel frames are lifted.

- Monitor course sediment movement to verify that coarse sediment is not impeding upstream adult fish passage, and continue until the sediment has been safely mobilized downstream. If passage is impeded, corrective measures would be enacted, in coordination with the resource agencies.

- Monitor upstream fish passage during the cofferdam deconstruction to ensure that no fish in the vicinity of the deconstruction area are showing signs of delay. If signs of delay are observed, notify the resource agencies as soon as possible within 24 hours and collaborate with the resource agencies to identify appropriate actions to be implemented to minimize the delay.

Remove Temporary Flow Diversion Berm and Fill Excavated Low-Flow Channel

- Return the Clackamas river channel in the vicinity of the powerhouse to approximately its pre-construction configuration, so that water in the diversion reach flows past the powerhouse outflow, so that fish passing the powerhouse would readily detect the upstream passage route, as they do under existing conditions.

Wildlife Resources

- Design any transmission lines and supports replacements according to avian-safe standards, including marking the lines with bird flight diversions to reduce bird collisions.

Cultural Resources

- Implement the MOA and mitigation measures: (1) provide State of Oregon documentation of the Faraday Powerhouse and related resources, (2) publish Faraday/Clackamas Project content using the Next Exit History application, (3) fund the digitization of multiple historic newspapers, (4) identify and interview people familiar with the operation of the Faraday Powerhouse to gather stories and personal histories of the plant, (5) plan and host a social gathering to be held at the powerhouse, (6) install a camera above the powerhouse site to provide time-lapse video of the powerhouse demolition and construction, which would be available on the internet, and (7) to the extent feasible, identify appropriate elements of the Faraday Powerhouse and related buildings for salvage and retention for interpretation/recreational use at the Faraday Dam Recreational Area.

- Implement the procedures of the Historic Properties Management Plan approved in the license if any previously undiscovered properties are found during construction.

Measures Related to Operation of the New Powerhouse

- Monitor water quality after the new powerhouse is installed to compare the monitoring results to equivalent data collected under existing conditions. Water quality variables to be monitored would include turbidity, temperature, dissolved oxygen, pH, algae, and total dissolved gas.

- Maintain project-wide downstream fish passage survival and injury standards outlined in the project license and assess whether conditions are in compliance with the project-wide standards.

- To evaluate potential post-construction adult salmonid mortality in the Faraday Powerhouse tailrace conduct surveys of the tailrace during the first three years following completion of the new powerhouse using the same procedure as those used in 2016 (i.e., sampling with an underwater camera once per month from July through October.)

- Develop a final post-Construction Stormwater Management Plan prior to commissioning the new powerhouse and ensure that the design and procedures associated with stormwater management are acceptable to ODEQ.

5.0 CONSISTENCY WITH COMPREHENSIVE PLANS

Section 10(a)(2)(A) of the FPA requires the Commission to consider whether and to what extent a project action is consistent with federal or state comprehensive plans for improving, developing, or conserving a waterway or waterways affected by the project action. Staff identified seven plans (listed below) that had the potential to be relevant to the Proposed Action. Staff found no inconsistencies between the Proposed Action and these plans.

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6.0 FINDING OF NO SIGNIFICANT IMPACT

If the proposed amendment to the Clackamas River Hydroelectric Project is approved with PGE's proposed measures, the project would continue to operate while providing protection and enhancements to water quality, aquatic resources, terrestrial resources, recreation, and cultural resources.

Based on our independent analysis, PGE's proposed demolition and re-build of the Faraday Powerhouse would not constitute a major federal action significantly affecting the quality of the human environment.

7.0 LIST OF PREPARERS

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Mark Pawlowski – (B.S. Biology, Graduate Course Work, Fisheries Management)

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Document Content(s)

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Michaela Lynn
Dain Nestel

February 15, 2023

Table of Contents

I. Introduction

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

A. My name is Michaela Lynn. I am the Senior Director of Customer Service at PGE.

My name is Dain Nestel. I am the Director of Sales at PGE.

Our qualifications are provided at the end of this testimony.

Q. Please summarize your testimony.

A. In our testimony, we explain PGE's forecast of Customer Service operations and maintenance (O&M) costs[1] for the 2024 test year and compare them to 2022, which represents PGE's most recent actual results. In the 2024 test year discussion, notable changes since the 2022 General Rate Case (GRC) are discussed. We then describe the incremental Transportation Electrification (TE) program funding and TE program accomplishments. Finally, we discuss changes to the expected uncollectible expense related to recent Division 21 rulemaking and economic conditions and describe how uncollectible expense was calculated for the 2024 test year.

Q. What is your primary goal for the Customer Service organization?

A. Our primary goal is to deliver exceptional customer experiences equitably and at a reasonable cost.

Q. How do you know if you are delivering exceptional customer experiences?

A. We gather customer feedback from three primary customer segments – residential, small to medium-sized businesses, and large commercial and industrial customers – through multiple

[1] PGE's Customer Service costs are consistent with Federal Energy Regulatory Commission (FERC) Chart of Accounts categories: Customer Accounts Expenses and Customer Service and Informational Expenses (*i.e.*, FERC accounts 901-910).

channels. This shows us how well we are serving our customers and enabling our business customers, and where we can make improvements. Customer feedback is gathered in a variety of ways:

- After customers complete transactions on our website, mobile app, automated phone system, and after they finish a call with our customer service advisors.
- Comments posted on social media and complaints submitted to the Public Utility Commission of Oregon (Commission).
- During customer satisfaction surveys on a quarterly, semi-annual, and annual basis.
- Customer focus groups and/or surveys on specific topics.

All feedback is used to identify areas of strength and areas of opportunity to improve PGE's customer service and to identify customer interest in new programs and service options.

Q. Have you seen changes in customer feedback over the years?

A. Yes. PGE's customer satisfaction ratings have improved over the years and reached an all-time high in 2020, before declining in the first quarter of 2021 following the February 2021 ice storm. Through 2022, PGE's customer satisfaction ratings have achieved top decile performance among residential customers and top quartile performance among Business customers in Escalent's National Energy Utility Benchmarking. Per Forrester's *Customer Experience Index*, PGE ranked number two in 2021 and number three in 2022 among 25 energy utilities measured, up from number ten in 2020. Customer expectations continue to increase in each of our three segments and customers increasingly expect PGE to understand their needs and offer solutions that meet those needs. Customers' migration to digital engagement (e.g., website, mobile application, Intelligent Voice Automation) creates an opportunity to capture their feedback as they are experiencing PGE's level of service.

This enables PGE to be more responsive to customers and/or confirm our programs or solutions are having positive impacts. In addition, many of our customers are looking for opportunities to participate in renewable energy (clean energy) programs in addition to what we currently offer so they can support a decarbonized future.

Q. Please describe the primary functions of PGE's Customer Service organization.

A. PGE's Customer Service organization is multi-faceted due to our support of three customer segments and the diverse needs within each segment. The services our teams offer include timely and accurate billing, a variety of payment options, start/stop/move service support, large customer new service coordination, enrollment in energy programs, and scalable digital platforms (e.g., website, mobile app). Our customer service teams also closely collaborate with other functions within PGE to respond to outages and provide restoration estimates, align customer projects with PGE's system planning, staff local community resource centers (which were activated to support customers during the Public Safety Power Shutoff in September of 2022), and communicate important updates to customers. Our focus is serving each customer with genuine care, being knowledgeable, and offering right-fit solutions that are delivered directly from the Customer Service organization or in collaboration with other PGE teams.

Q. Does the Customer Service organization perform other functions as well?

A. Yes. We develop, promote, and coordinate a variety of programs. These programs include demand response and other distributed energy resource programs that are central to PGE's Virtual Power Plant (VPP), renewable energy programs and energy efficiency offers, plus an assortment of grid services that help customers through their entire energy journey. In several of these programs, we collaborate with Energy Trust of Oregon to enhance cost efficiency and participation levels. In addition, we continue to research, evaluate, develop, and implement pilots and/or programs that will have a meaningful impact on our customers' lives and businesses. Our focus is on making it easy for our customers to do business with PGE, to be accessible in the channel they choose, and to provide additional support for those customers that need it. We also collaborate with PGE's cross-functional teams to provide safe, expert solutions. Ultimately, we strive to earn each customer's business and their trust with exceptional experiences and solutions, and we do so by performing all these functions timely, accurately, and efficiently.

Q. What recent enhancements and changes have been made to meet customer expectations?

A. In 2022, PGE unveiled a new streamlined easy-to-read bill for residential customers. The goal of the redesign was to simplify the way we present information to customers, make the bill more intuitive, and reduce the need for customers to call with bill questions. We recently surveyed customers on the new bill design and the results are positive. One highlight from the survey came from our Time Payment Arrangement and Equal Pay customers, who shared that 100% of them were satisfied with those new bills — these have historically been two of our most confusing bills for customers. A second significant enhancement for customers was the launch of our mobile app in Spanish in early 2022. Diversity, equity and inclusion are core to our company. We want our customers who prefer to do business in Spanish to feel seen by PGE and have an enjoyable digital experience.

Q. How is the remainder of your testimony organized?

A. In Section II, we explain PGE's request for forecasted 2024 O&M costs in comparison to 2022 actual costs, including a discussion of customer payment preferences and the resulting impact to payment processing fees. In Section III we provide an update on the progress of our TE program and incremental expenses. In Section IV we describe changes to uncollectible expense following the COVID-19 pandemic and Division 21 rulemaking. We provide concluding remarks in Section V, and our qualifications are summarized in Section VI.

II. Operations and Maintenance Costs

Q. What is PGE's forecast of Customer Service O&M costs for the 2024 test year?

A. PGE forecasts approximately $107.2 million in total Customer Service O&M for 2024, including uncollectible expense, which is a revenue sensitive cost. This represents a $22.8 million increase relative to PGE's 2022 actual costs. The overall increase to Customer Service O&M is attributed primarily to the following five factors: 1) cost escalation since 2022;[2] 2) an increase in the uncollectible expense in 2024 compared to 2022, during which the COVID-19 Bad Debt deferral was in effect; 3) higher payment processing expense; 4) additional expense for customer outreach and education; and 5) increases to support growing TE programs, and other customer initiatives. Table 1 summarizes these costs, which are discussed in more detail below.

Table 1
Customer Service O&M Expenses ($ Millions)

Category	2021 Actuals	2022 Actuals	2024 Forecast	(2024-2022) Delta*
Labor	$25.8	$30.0	$35.5	$5.5
Non-Labor	$21.9	$19.2	$26.0	$6.8
Subtotal*	**$47.7**	**$49.3**	**$61.5**	**$12.3**
Information Technology	$32.6	$28.1	$32.3	$4.2
Subtotal*	**$80.3**	**$77.4**	**$93.8**	**$16.5**
Uncollectibles[3]	$6.0	$7.0	$13.4	$6.4
Total Base Business Costs*	**$86.3**	**$84.3**	**$107.2**	**$22.8**

** May not sum due to rounding*

Q. What accounts for the increase in labor costs from 2022 to 2024?

A. Reasons for O&M labor increases in customer service include the following:

[2] PGE Exhibit 200 provides the cost escalation factors that PGE used in developing its 2024 test year forecast. PGE Exhibit 500 provides additional detail regarding labor escalation.
[3] 2021 and 2022 uncollectible expense reflect lower amounts due to the COVID-19 deferral, which deferred uncollectible expenses above the previously approved amount in Docket Nos. UE 335 and UE 394.

- Approximately $2.6 million due to wage and salary increases, which are discussed in further detail in Exhibit 500.
- Approximately $2.0 million increase in labor due to higher vacancies in 2022 compared to forecasted 2024. The labor market in 2022 experienced slightly higher turnover rates as well as more challenges in filling positions. In 2023 and 2024 the labor resources are projected at levels needed to sustain the customer services organization and support growing customer program offerings.
- Approximately $1.0 million increase related to labor charging more heavily to Administration & General (A&G) expense accounts in 2022 actuals compared with a 2024 forecast of labor in customer service Federal Energy Regulatory Commission (FERC) accounts.

Q. Please explain the forecasted increase in non-labor costs from 2022 to the 2024 test year forecast.

A. In addition to cost escalations, the main drivers of non-labor costs in customer service from 2022 to 2024 are related to:

- Approximately $1.8 million for increased activity in our TE programs and Electric Vehicle (EV) Field Operations, which is discussed in Section III.
- Approximately $1.5 million increase related to outreach and education to customers of how the electrical grid is evolving, what it's going to take to get to decarbonization on the Path to 2030 and beyond and how customers can take advantage of the numerous clean energy rebates and incentives to cost-effectively manage their energy use.
- Approximately $1.5 million increase in payment processing fees and related billing expenses.

- Approximately $0.7 million increase reflecting a temporary and unsustainable reduction in 2022 with budget levels restored in 2023 and 2024.

Q. Do you address IT costs in this testimony?

A. Yes. The increase in IT expense is predominantly driven by greater use of software programs in the customer service area. The increased use of customer service software programs also corresponds to an increase in associated maintenance/support costs, as well as increased amortization expenses. IT costs are charged or allocated to all operating areas of the company and further details are discussed in PGE Exhibit 600, Section III.C.

Q. What is the 2024 test year forecast for uncollectible expense?

A. We are forecasting uncollectible expense of $13.4 million in 2024, which is a revenue sensitive cost and discussed in greater detail in Section IV below.

Q. Please describe the O&M increase related to additional outreach and customer education.

A. As we transition toward a clean energy future it is important for customers to both be aware of our Path to 2030 House Bill (HB) 2021 clean energy goals and community-wide initiative that will require all of us working together collectively and for customers to know how they can play a role in our evolving grid and decarbonization efforts. As the grid is increasingly multi-directional, customers will have more opportunities to save energy and money be it through technologies, programs and tax credit or other rebates to participate through direct action in decarbonization. PGE plans an education and outreach effort to support customers in their decisions to interact with the grid and invest in new technologies that will help them save money and energy.

Q. What are the available payment channels that customers can use to pay their utility bills?

A. Our customers can pay their bills on the PGE website, through PGE's mobile application, through an automated phone system, face-to-face with CheckFree Pay locations and Western Union, through their financial institution's bill "pay option", including traditional checks, over the phone with a PGE Customer Service Advisor and through various online payment platforms (PayPal, Amazon Pay, and in the future, Google Pay and Apple Pay). Additionally, some commercial customers pay via electronic data interchange (EDI).

Providing multiple payment channels provides customers with the ability to do business with us in the way they choose whether digitally or in person. Recent data shows that as calls for past due reminders have been made to our customers, approximately 90% of the phones we call are cell phones, highlighting the usefulness of digital options. All these options are easy and secure but require the ability of the customers to use a debit or a credit card, which necessitates expanded use of the Fee Free Bank Card as adoption grows.

Q. Please provide a brief summary of the debit and credit card payment adoption for residential customers.

A. Prior to 2015, if a customer chose to pay their utility bill with a card, whether debit or credit, they were assessed a transaction fee. PGE began offering fee free debit and credit card processing for residential customers in 2015, as approved by Commission Order No. 14-422.[4] Adoption has steadily increased; approximately 30% of all payments from PGE's residential customers use a debit or credit card to pay their bill as of the end of 2022, up from 10% in 2020.

[4] Docket No. UE 283, Order No. 14-422 limits the Fee Free Bank Card Program to residential customers.

Q. Please describe how the residential payment processing fees forecast for the 2024 test year was developed.

A. The 2024 test year forecast was developed using the recent trend in residential card payment usage. The forecast is for an additional 10% adoption of card payments by 2024 based upon these adoption trends, multiplied by the per transaction fee. The increase to residential card payment count is offset by a reduction in echeck payment count by a commensurate amount. Residential card payment as a share of all payments is forecasted to grow to approximately 42% on average in 2024.

Q. Please provide a brief summary of commercial customer use of bank cards.

A. In 2020, commercial debit and credit card payments made up less than 2% of PGE's overall payments, with over 92% of these customer payments represented by small businesses (Schedule 32). Although small business customers are classified as commercial business customers, they more closely resemble residential customers than larger nonresidential customers in their usage and bill payment behavior. To alleviate the financial stress during the COVID-19 recession, PGE notified Commission Staff and proceeded to temporarily waive the debit and credit card transaction costs for all non-residential customers. PGE continued offering fee free debit and credit card processing for commercial customers in 2022 with a limit of $1,500 per billing cycle, as approved by Commission Order No. 22-129. Continuing to offer the fee free bank card option is responsive to commercial customer interest in using fee free bank cards and reduces a primary source of commercial customer frustrations regarding our electronic payment options prior to the offering. Commercial customer adoption of card payments has increased to approximately 10% of commercial payments in 2022 and is expected to continue to grow with increased awareness of this payment channel.

Q. Please describe how the 2024 test year commercial payment processing fee forecast was developed.

A. The 2024 test year forecast was developed assuming consistent adoption as in 2022. The commercial payment processing fee is flat in 2024 compared to 2022.

Q. What is the additional O&M expense you included in your 2024 payment processing and related billing expense forecast based on the above forecast methods?

A. The increase in the 2024 test year O&M expense for payment processing fees is $1.5 million.

III. Transportation Electrification (TE)

Q. Please discuss the changes to and progress of PGE's TE program since the 2022 General Rate Case.

A. PGE's 2022 GRC was approved in April of that year. At the time, Commission Staff, stakeholders, and utilities were engaged in informal rulemaking under Docket No. AR 654 to prepare updates and revisions to the Division 87 rules governing customer-facing utility TE plans. Parties were also actively engaged in dialogue around the development of a TE investment framework under Docket No. UM 2165. Additionally, that same month, PGE kicked off a series of five stakeholder workshops that ran through the fall, to seek input on customer programs, infrastructure measures, and other activities to be included in the Company's next TE plan. We also developed, sought stakeholder input on, and filed a budget in July 2022 for the expenditure of revenues collected that year through the HB 2165 Monthly Meter Charge (MMC), which the Commission approved in October together with associated infrastructure measure applications.[5]

The cumulative effect of these efforts is that the focus of PGE's TE program since the 2022 GRC has been on forward-looking planning and development while continuing existing, Commission-approved activities that support customers' transition to the use of electricity as a transportation fuel. New programmatic activity has centered on deployment of 2022 MMC revenue and development of proposals for inclusion in the next TE plan.

PGE's upcoming TE plan, slated for filing on or before June 1, 2023,[6] will present proposals for TE programs for 2023 through 2025, including the 2024 test year. This plan will

[5] *See* Order No. 22-381, available at: https://apps.puc.state.or.us/orders/2022ords/22-381.pdf.
[6] *See* Order No. 23-034, issued 2/8/2023, available at: https://apps.puc.state.or.us/orders/2023ords/23-034.pdf.

evolve our current offerings into a comprehensive portfolio of programs, infrastructure measures and other activities in support of TE. Our goal is to equitably and affordably address customer needs and TE-related load growth across customer segments, modes of transportation, and types of vehicles in keeping with statutory requirements and Commission guidance as well as input from stakeholders.

Q. Please describe the benefits PGE's TE program brings to customers.

A. The planning functions described above, together with the continuation and expansion of existing activity, have and will continue to benefit customers through improved TE program and measure design, particularly the TE-related services offered to historically underserved communities.

Oregon surpassed 50,000 registered EVs in 2022,[7] and ranks third nationally among the states for the number of EVs registered per 100,000 people.[8] This, combined with increasing up-front price parity between EVs and their internal-combustion counterparts, Oregon's recent adoption of the California Air Resources Board's Advanced Clean Cars II Rule (which bans the sale of new gas- and diesel-powered vehicles by 2035),[9] and equity considerations drive the expectation that customer demand for EV charging infrastructure and other support will continue to expand rapidly. PGE forecasts EV adoption in our service area to grow to 133,506 vehicles (including commercial) by the end of 2025 and potentially half a million EVs by 2033.[10] This level of EV adoption will carry with it significant load growth, which

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[7] *See* State of Oregon Electric Vehicle Dashboard, available at: https://www.oregon.gov/energy/Data-and-Reports/Pages/Oregon-Electric-Vehicle-Dashboard.aspx.

[8] Chris Gilligan, States With the Most Electric Vehicles, Us News & World Report, Aug. 19, 2022, available at: https://www.usnews.com/news/best-states/articles/2022-08-19/states-with-the-most-electric-vehicles.

[9] David Steves, *Oregon, Washington Join California in Banning New Vehicles Starting in 2035*, OPB, Dec. 20, 2022, available at: https://www.opb.org/article/2022/12/20/oregon-washington-ban-gas-powered-vehicles-2035-joining-california/.

[10] PGE's EV adoption forecast is derived as part of the Company's Distribution System Planning process, using the AdopDER forecasting model.

will require expansion of TE programs that help minimize peak load resource requirements. As an electric utility and transportation fuel provider, we must resource our TE program to build out this critical component of our core business, efficiently integrate the load from these vehicles onto the grid and meet our customers' current and future needs. We must accomplish this while keeping customer prices affordable. Our customer-focused strategy to address this need will be described in our upcoming TE Plan and is reflected in our forecasted O&M expense for TE described below.

Q. What TE costs are included in base rates and what costs are recovered through other mechanisms?

A. Base rates will be used to recover costs associated with customer-facing TE portfolio administration and planning, customer fleet charging enablement, future charging infrastructure, program management, software licensing fees, non-capitalized engineering-related costs, hardware maintenance, and data analysis.

PGE maintains Commission-approved accounts to recover TE pilot costs included in Docket Nos. UM 1938 and UM 2003 through Schedule 150. These include O&M and capital expenditures relating to our Electric Avenue Network, Electric Mass Transit Pilot, residential smart charging rebates, and business charging rebates as well as outreach/technical assistance and pilot evaluation.

Note also that the MMC is collected through Schedule 150 and is a statutory charge to customers levied to support TE. PGE will charge applicable costs against MMC revenues using a balancing account in accordance with annual MMC budgets approved by the Commission.

Q. What is your forecast of 2024 customer service O&M expenses associated with TE and how much is incremental to 2022 actuals?

A. PGE's 2024 forecast for TE customer service O&M is approximately $2.7 million, including $1.8 million of non-labor expenses and $0.9 million of labor expenses, which are incremental to 2022 actual costs. Increases in non-labor represent expenses such as planning and design, charging data management and analytics, market studies, and program evaluation. Increases in labor expenses reflect temporary spending reductions in 2022 with budget levels restored in 2023 and 2024, normal labor escalations, and additional support dedicated to customer grid management programs. These modest increases will be used to help manage EV-related growth on our system through expanded load management programs that support the rapid expected increase in customer EV adoption in our service area described above.

Q. Are PGE's own fleet electrification costs included in this forecast?

A. No, this forecast is for customer service O&M and does not include electrification of PGE's own fleet.

IV. Uncollectible Expense

Q. What is the 2024 test year forecast for uncollectible expense?

A. The 2024 test year forecast for uncollectible expense is $13.4 million. This is $6.4 million higher than 2022 uncollectible expense of $7.0 million, however the 2022 amount reflects a lower amount than would have otherwise been experienced due to the deferral of bad debt under the COVID-19 deferral. If not for the deferral of uncollectible expenses above the previously approved GRC amount in 2022, uncollectible expense would have been approximately $8.9 million higher than shown in Table 1.[11] Uncollectible expense is higher in 2024 compared with 2022 due to the deferral of excess uncollectible expense in 2022, making 2022 lower and also a higher forecasted uncollectible rate in 2024 due to the forecasted economic conditions in 2023 and 2024 and changes to Oregon Administrative Rules, Chapter 860, Division 21 (Division 21 rulemaking) following the COVID-19 pandemic. Adjusting for the deferral, this would indicate a net ***reduction*** of approximately $2.5 million between 2022 and 2024, as excess uncollectible expense is no longer deferrable since the end of the COVID-19 deferral at the end of 2022.

Q. How did you forecast PGE's uncollectible expense for 2024?

A. The 2024 uncollectible expense is calculated using an uncollectible rate which is forecasted using a combination of historical uncollectible rate trends, with adjustments for forward looking economic conditions, Division 21 rulemaking changes, and factoring in the end of COVID-19 bill assistance programs. The result of these adjustments is an uncollectible rate estimated at 0.5272%, as shown in Table 2 below. To mitigate the customer price increase in

[11] PGE deferred $26.8 million of uncollectible expense for the years 2020 to 2022 (i.e., bad debt) and bill assistance under the COVID-19 deferral. This is approximately $8.9 million per year if divided evenly over the three years.

this GRC, we have assumed a lower uncollectible rate of 0.5% which is applied to the 2024 test year revenue requirement, as uncollectible expense is revenue sensitive. This customer price mitigation (i.e., reduction to PGE's test year request) by using a lower rate than supported by our analysis is approximately $0.7 million.

Table 2
Uncollectible Rate Forecast Itemized

Description	**Uncollectible Rate**
UE-335 (2019 GRC Workpaper, used in the 2022 GRC), Uncollectible Rate in Strong Economic Conditions	0.3262%
Impact of mild recession/balanced economic conditions assumption	0.0842%
COVID bill assistance going away	0.0265%
Deposit Adder	0.0258%
Division 21: Weather Disconnect Provisions	0.0544%
Division 21: Notice perspective 15 day to 20 day	0.0272%
Collection Agency Recovery Rate trending lower	0.0545%
IQBD (lowers bill amounts)	-0.0716%
Forecasted Uncollectible Rate	**0.5272%**
Proposed Uncollectible Rate in Revenue Requirement	**0.5000%**

Q. How did you forecast PGE's uncollectible expense in prior GRCs?

A. In Docket No. UE 335, the 2019 test year GRC, the uncollectible rate was estimated based on a 3-year historical average from 2015 to 2017 at 0.3262%. In Docket No. UE 394, after reviewing the effects of increasing our uncollectible expense to reflect economic conditions, and because we had the COVID-19 deferral in place to address the additional uncollectible expense, we chose not to increase the uncollectible rate at that time. The historical average of 2015 to 2017 reflects strong economic conditions in PGE's service territory and is used as the starting point for the establishment of the uncollectible rate for 2024.

Q. How do economic conditions affect uncollectible expense?

A. Uncollectible expense typically increases during periods of economic downturn and is lowest during strong economic conditions. History has shown that in prior years of economic downturns, uncollectible rates can reach 0.5% or higher, which is approximately 0.2% higher than during strong economic conditions. The increase in uncollectible rates in economic downturns also show persistence or lag following the beginning of a recession.

Q. What is the economic forecast for the 2024 test year?

A. Current economic forecasts from the Oregon Office of Economic Analysis (OEA) and IHS Markit, among other mainstream forecasts, now show a mild recession occurring in 2023 into 2024. The Oregon OEA included a recession in their baseline Economic and Revenue forecast released in December 2022 with job losses beginning in the third quarter of 2023 until job growth resumes in the second quarter of 2024, with Oregon recovering the job losses by the end of 2024.

Q. How did you factor economic conditions into the proposed uncollectible rate?

A. An increase of 0.084% was added to the baseline uncollectible rate to be more balanced between the historically stronger economic conditions and forecasted future downturns or periods of lower growth and due to the economic environment forecasted for 2023-2024. The 0.084% adjustment represents half of the estimated impact of economic downturns to reflect this balancing of strong and weaker economic conditions. We also use half of the recessionary impact to reflect the milder nature of the expected 2023 recession.

Q. How do you factor in the expiration of COVID-19 related bill assistance?

A. We estimate that the expiration of COVID-19 bill assistance will increase the uncollectible rate by approximately 0.0265%. There was approximately $1.5 million in write offs that were associated with accounts that received bill assistance after February 2021. During that same time period, there were $18.5 million in gross write offs. Therefore, gross write offs would have been 8.1% higher. Applying the 2021 collection agency recovery percentage of 28.5%

results in a 2.6% increase. The COVID-19 related bill assistance was in addition to strong federal fiscal policies that also mitigated gross write-offs over the past two years.

Q. How does PGE anticipate Division 21 rulemaking will affect uncollectible expense?

A. Division 21 includes several rule changes for collection activities for residential customers which we expect to affect uncollectible expenses. Any rule changes that increase arrearage balances, such as additional notification time, reduced options for holding security deposits, smaller disconnection windows or seasonal moratorium on disconnects, will increase the uncollectible rate.

Q. How did you adjust the uncollectible rate for the changes in the Division 21 rulemaking?

A. The following adjustments were made to the forecasted uncollectible rate for Division 21 rulemaking changes:

- With respect to the weather credit limitations, an adjustment of 0.054% was added to the uncollectible rate. This represents 90 extra days of balance rollover caused by the expected reduced ability to disconnect in the winter months.
- With respect to the additional notification days, an adjustment of 0.027% was added to the uncollectible rate. This represents five extra days of balance rollover caused by the expected inability to disconnect in the winter months.
- With respect to the end of deposits for residential customers, an adjustment of 0.026% was added to the uncollectible rate. This represents the residential deposits that were associated with write offs in 2019, the last year before the COVID-19 pandemic. In 2019 there were approximately $0.5 million deposits paid that were associated with write offs. Thus, these balances were deducted from PGE's write offs.

Q. How did you adjust the uncollectible rate for the Income Qualified Bill Discount Program?

A. The Income Qualified Bill Discount Program (IQBD) reduces the billed amount for certain eligible residential customers. While this program has not had a discernible impact on the uncollectible rate so far, a program that reduces billed amounts could lower uncollectible expense in the future. Therefore, we decreased the estimated uncollectible rate by -0.072% to take into account the potential impact from IQBD. This was estimated by extrapolating the potential reduction in uncollectible expense based on enrollees in IQBD which are 61+ days arrears.

Q. How did you adjust the uncollectible rate for collection agency recovery rate trends?

A. We have seen a reduction in collection agency recovery percentage in recent years. Additionally, in response to inflationary pressures, the Federal Reserve has implemented policies and Federal Fund Rate increases to raise interest rates. Higher interest rates and economic uncertainty reduces collection agency recovery rates. Changes to Fair Debt Collection Regulation enacted in late 2021 have further eroded collection agency recovery rates through provisions addressing and limiting collectors' use of email, text messages, and other electronic media. With respect to reduced collection agency recovery percentage, an adjustment of 0.055% was added to the uncollectible rate. This represents the change from a recovery percentage in 2021 of 28.5% to 16.5% in 2022.

V. Conclusion

Q. Please summarize your request regarding Customer Service costs in this proceeding.

A. PGE requests that the Commission approve PGE's forecasted increase in Customer Service O&M costs as described in Sections II through IV above, to be effective in prices January 1, 2024. These costs are necessary for PGE to provide timely and accurate customer usage data plus effective metering, billing, collection, and response services to all customers. These costs also allow us to modernize the grid and implement new programs and service options that provide benefits to customers, including the VPP, expansion of PGE's TE work and continuing to provide modern payment channel options to residential and small business customers.

VI. Qualifications

Q. Michaela Lynn, please state your educational background and experience.

A. I received a Bachelor of Science from Colorado State University. I have worked at PGE since 1997 with the majority of that time spent leading in our Customer Service area including Customer Care (call center serving residential, business and builders/developers in multiple channels – phone, social media and email) and Customer Revenue (Billing, Credit, Payment, Automated Metering, etc.).

Q. Dain Nestel, please state your educational background and experience.

A. I received a Bachelor of Arts from the University of Oregon and a Master of Business Administration from Kellogg School of Management. I have been in the energy industry since 2008 where I consulted to utilities on energy efficiency and demand response program design and implementation. I led ecobee's energy channel sales in the West starting in 2018 before joining PGE in 2019 where I oversee our sales and outreach teams, program development and implementation teams, e.g., Flex Load and TE, and PGE's partnership with the Energy Trust of Oregon.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Christopher Liddle
Bente Villadsen

February 15, 2023

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, Controller and Assistant Treasurer at PGE.

My name is Bente Villadsen, and I am a Principal of The Brattle Group, whose business address is One Beacon Street, Suite 2600, Boston, Massachusetts, 02108. I have been asked by PGE to estimate the cost of equity that PGE should be allowed an opportunity to earn on the equity portion of its rate base for the period starting January 1, 2024. I directly sponsored the testimony found in Section IV.

Our qualifications are provided at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to recommend PGE's authorized cost of capital and capital structure for the 2024 test year. PGE's cost of capital and capital structure were last approved in Public Utility Commission of Oregon (Commission) Order No. 22-129 in April 2022.

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 2024 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[1] and Hope[2] United States Supreme Court decisions, as well as ORS 756.040.

[1] *Bluefield Waterworks & Improvement Co. v. Public Service Comm'n of West Virginia et al.*, 262 U.S. 679, 43 S.Ct 675 (1923).

[2] *Federal Power Commission et al. v. Hope Nat. Gas Co., et al.*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1944).

Q. What is PGE's requested overall cost of capital for this filing?

A. We request and support a 7.059% cost of capital for the 2024 test year. This cost of capital reflects PGE's updated request for return on equity (ROE) of 9.80%, its currently authorized capital structure of 50% debt and 50% equity, and an updated long-term cost of debt of 4.317%.

Table 1 below shows the recommended cost of the two components of PGE's capital, common equity and long-term debt. Table 1 also shows PGE's forecasted 2024 regulatory capital structure.

Table 1
PGE's Weighted Cost of Capital
Test Year 2024

Component	**Average Outstanding ($000) [1]**	**Percent of Capital [2]**	**Component Cost**	**Weighted Cost**
Long-term Debt	$3,808,800	50%	4.317%	2.159%
Common Equity	$3,668,196	50%	9.800%	4.900%
Total	**$7,363,870**	**100%**		**7.059%**

[1] "Average Outstanding" reflects PGE's projected average values of long-term debt and common equity for 2024.

[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. In the following section, we provide an overview of PGE's financial goals, how markets and regulatory environments impact PGE, and how PGE manages counterparty risks and liquidity.

- Section III discusses PGE's cost of long-term debt, including new and redeemed issuances;
- Section IV provides the updated analysis that supports PGE's requested ROE of 9.80%;
- Section V discusses PGE's capital structure; and
- Section VI provides our 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 adequate capital and liquidity to fund PGE's operations at the least cost and least risk to customers. While this is always a key element of PGE's financial goals, it will be even more critical for PGE to maintain a strong financial position and access to low-cost capital through 2030 as we invest to meet the decarbonization targets set forth and adopted in House Bill 2021 during the 2021 legislative session.

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?

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 that is commensurate with the return on equity 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; and
- 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 risks to protect our customers and PGE. We engage in ongoing 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 will aid us in meeting our 2030 decarbonization goals.

Q. How does access to low-cost capital benefit our customers?

A. Low-cost capital benefits our customers in many ways. Our customers want reliable, clean energy at an affordable price that is transmitted safely to them. In order to invest in resources that are clean 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 used to fund new clean energy resources such as the Clearwater Wind Project and 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 as a business model 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 ability to access capital at a low cost?

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, although it may fluctuate somewhat from year to year. 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. How does PGE maintain its capital structure at 50% equity and 50% long-term debt?

A. To maintain this capital structure, PGE primarily monitors the size and frequency of its debt issuances. In the future, PGE plans to continue to use equity issuances, stock repurchases, capital expenditure programs, the debt markets, letters of credit, and cash from operations to help maintain PGE's desired capital structure.

Q. Why is it important for PGE to maintain investment grade credit ratings?

A. It is important for PGE to maintain investment grade credit ratings in order 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 its ability to manage costs. The 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 various 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. Using all of these measures helps PGE maintain financial performance levels necessary for investment grade credit ratings.

Q. What are PGE's current bond ratings?

A. PGE's current 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, which were recently affirmed, are provided in PGE Exhibit 1002.

Q. Have PGE's bond ratings changed recently?

A. The most recent change in PGE's rating occurred in July 2018 when S&P upgraded PGE's rating on its long-term debt. PGE's long-term debt rating from Moody's remains one notch higher than S&P.

Q. Have rating agencies recently changed outlooks on PGE?

A. Not since PGE's 2022 general rate case. Both S&P and Moody's maintain a 'stable' outlook for PGE pursuant to their most recent 2022 reports.

Q. Please describe the factors rating agencies consider when evaluating PGE's creditworthiness.

A. Creditworthiness describes a company's overall financial health and its 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) 40% regulatory environment and asset ownership model (this includes stability and predictability of regulatory regime, cost and investment recovery, and revenue risk); 2) 10% scale and complexity of capital program; 3) 10% financial policy; and 4) 40% leverage and coverage (this includes ratios on cash flow, debt service coverage, leverage, and interest coverage).

Q. Please describe further what is included in rating agencies' consideration of the "regulatory environment."

A. As stated by Moody's in a report published on March 30, 2022 (March 2022 report), a regulated utility's regulatory environment "greatly influences the stability and predictability of its cash flows."[3] The ability to recover prudently incurred costs promptly is extremely

[3] "Portland General Electric Company: Update to Credit Analysis." Moody's. 30 March 2022.

important because a delay in cost recovery may cause financial stress. Decisions made within the regulatory environment are critical to protect the Company's credit quality, its ability to recover its costs, and to earn a fair and reasonable return. The rating agencies place a high value on stability, predictability, consistency, and transparency in regulation.

Q. What recent concerns have been expressed by the rating agencies regarding PGE's creditworthiness?

A. In the March 2022 report cited above Moody's noted that 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."[4]

Q. Did Moody's March 2022 report identify any other potential risk to PGE's creditworthiness?

A. Yes. It was noted 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%."[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 important indicator of the financial strength and liquidity of a regulated utility by Moody's.[6] Many actions could drive down CFO pre-WC to debt. Most notably from a financing perspective, any changes in PGE's capital structure could impact this metric. Specifically, an

[4] "Portland General Electric Company: Update to Credit Analysis." Moody's. 30 March 2022.
[5] *Id.*
[6] "Rating methodology: Regulated Electric and Gas Utilities" Moody's. August 2009.

increase in debt would lower this financial ratio. As stated below, 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 more expensive service for PGE customers. As explained above, a lower credit rating would mean an increase in the cost of debt and impact PGE's ability to attract equity capital at a reasonable price, thus leading to higher overall costs for customers.

Q. Financial performance is an important element for rating agencies and investors. What other factors are considered?

A. Other factors that are considered by both rating agencies and investors include regulatory policy and recovery risk (as mentioned in the March 2022 Moody's report), corporate operations and growth, customer and portfolio diversification, and liquidity and other financial measures. We note that both PGE's rating agencies and investors have expressed concern with PGE's earnings volatility due to one-time but significant write-offs, the asymmetric deadband on the Power Cost Adjustment Mechanism (PCAM), and Oregon's regulatory policies, in general.

Q. You noted above that rating agencies consider a utility commission's regulatory policy when determining a company's rating. Can you provide some additional detail?

A. Yes. Regulatory policy that supports timely recovery of prudent costs is essential to maintaining a stable, investment grade credit rating. Both Moody's and S&P consider regulatory policy a key factor in their determination of a utility's creditworthiness. As mentioned, Moody's places 40% weight on the "Regulatory Environment and asset ownership model."[7] 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. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support."[8] Other key characteristics in the assessment of the regulatory environment for both credit rating firms include the consistency and predictability of Commission decisions, as well as the timely recovery of prudently incurred costs.

Q. You said that 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. Ultimately 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[9] granting PGE's motion for

[7] With the other three factors and their weights being "Scale and Complexity of Capital Program 10%, Financial Policy 10%, Leverage and Coverage 40% "Rating Methodology – Regulated Electric and Gas Utilities." Moody's Investor Service.
[8] "Key Credit Factors for the Regulated Utilities Industry." Standard & Poor's- November 19, 2013.
[9] *See* Docket No. UE 394, Order No. 22-188, granting PGE's Motion for Clarification.

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 write-off for the emergency events?

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 prior to the write-off, 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. Have the rating agencies and investors shown concern regarding other regulatory mechanisms?

A. Yes. Both the rating agencies and investors have continued to express concern regarding the PCAM, the risk it introduces to PGE generally, along with the growing risk it provides as Oregon and the Western Interconnect move away from stable dispatchable resources toward variable renewable resources.

In addition to concerns expressed by the rating agencies and investors, financial analysts have also expressed concerns regarding the PCAM. Notably, that the asymmetrical deadband feature of the PCAM is abnormal. Nearly every other state commission in the United States allows for a pass-through mechanism of investor-owned utility power costs, with no deadbands. Thus, it is not surprising that analysts are concerned about not just a wide deadband, but also its asymmetric allocation of benefits since either can result in meaningful impacts on PGE's earnings thereby increasing volatility.

Q. Could you give examples of comments made by investors, financial analysts and/or rating agencies regarding the PCAM?

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

In March 2022, Moody's recognizes the PCAM as a credit challenge by noting PGE's "exposure to unrecoverable power costs via asymmetric customer sharing of actual costs."[14]

Q. How does increased earnings volatility via the PCAM impact PGE's cost of capital?

A. Generally accepted financial theory is: all else equal, increased earnings volatility results in increased uncertainty and risk and, thus, requires a higher return to investors. As dispatchable resources become scarcer, PGE is still required to prioritize reliability and then

[10] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[11] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[12] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[13] **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**

[14] "Portland General Electric Company: Update to Credit Analysis." Moody's. 30 March 2022.

decarbonization before it can make decisions that impact the economic outcome of power costs. As extreme weather events become more and more frequent, PGE becomes less capable of economically managing power costs. This situation, combined with the restrictions on power cost recovery within the current PCAM structure, increases uncertainty and risk.

Given that PGE's current 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. In this environment, PGE's investors and creditors will require much greater compensation to offset the higher risk because, all else equal, a company with greater earnings volatility will have a higher cost of capital than a company with more stable earnings.

Q. Why does it matter if investors compare PGE to other utilities with straight pass-through recovery of power costs?

A. When setting fair and reasonable rates, the Commission is tasked with balancing the interests of utility investors and consumers. Under ORS 756.040, rates are considered fair and reasonable if they provide investors a return "that is: (a) commensurate with the return on investments in other enterprises having corresponding risks; and (b) sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital." If investors consider PGE riskier than other utilities because of our PCAM mechanism, then PGE's return on equity must be set higher to ensure PGE's rates are fair and reasonable.

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 connected with imputed debt from power purchase agreement (PPA) contracts. S&P "imputes" additional debt to PGE's capital structure based on the payments under long-term PPAs. S&P believes that because of these quasi-debt instruments, an adjustment must be made to the capital structure to reflect the additional leverage of PPAs. As PGE acquires additional long-term capacity contracts and QF contracts, this imputed debt adjustment could result in increases in the debt ratio large 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, and a delayed draw/forward structure to arrive at the lowest reasonable financing costs available at the time of PGE's financing need.

Q. How does PGE determine the timing of its financing?

A. PGE forecasts its cash needs, which include capital expenditures, debt maturities, dividends, and changes in working capital, and attempts to match its long-term financing proceeds to meet those requirements. PGE aims to issue long-term debt so that debt maturity schedules closely match the investment schedules of its capital projects. In the past, PGE has used a delayed draw for its long-term bonds that allowed us to fix the interest rate on the upcoming bond issue, removing interest rate and funding risk.

Q. Does PGE have any debt or equity issuances on the horizon?

A. Yes. In October 2022, PGE announced an equity issuance of 11 million shares at a price of $43 per share using a forward agreement. PGE expects to settle the forward agreement **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** at which time PGE will issue shares to the forward purchasers, Barclays and JP Morgan, in exchange for cash. The equity issuance helps PGE strengthen its balance sheet, repair its common equity ratio, and finance clean energy investments including the Clearwater Wind Project. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

In addition, PGE is anticipating **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** through the 2024 test year 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 shut down of customer facilities, curtailment of customers' operations, or changes in capacity as a result of economic or specific circumstances. In 2022, as a reflection of supply chain constraints and raising wages, PGE has seen an increased risk in weighted credit scores from our top 540 commercial customers who represent approximately 60% of our commercial and industrial revenues. These companies come from a range of industries, with transportation, construction, retail, and distribution being the primary industries driving this risk increase.

Q. How does PGE manage its customer credit risk exposure?

A. For non-residential customers, PGE attempts to minimize the impact of customer defaults and manage 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, such as the case of the Cineworld bankruptcy in 2022 wherein PGE was able to recover all outstanding balances through deposit.

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 business forecasts provided by large customers and their potential consequences on PGE's retail load. After review, PGE determines the appropriate deposit required from a large customer. This deposit typically is up to one-sixth of the annual bill.

Q. How does PGE manage counterparty risk?

A. PGE manages its counterparty risk in wholesale power transactions using the same methods as for large customers. Specifically, PGE performs credit reviews of wholesale power counterparties, both purchasers and sellers, and then 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, similar to how it manages credit risk for large customers and other counterparties.

C. Liquidity Management

Q. What is PGE's strategy for liquidity management and related revolving credit facility sizing?

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.
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 yields the total liquidity requirement for PGE's needs. This approach enables PGE to ensure that its power and gas procurement efforts have enough liquidity to meet collateral requirements, while also maintaining sufficient liquidity for other operations.

Q. When did PGE last perform such an analysis?

A. PGE last analyzed its revolving lines of credit requirements in October 2022.

Q. What were the results of that analysis?

A. At present, PGE's $650 million revolver and $220 million letter of credit facilities protect against our modeled power supply risk and mitigate the compounding risk of restricted capital market access. However, given PGE's expected capital expenditures to support decarbonization, an increase in the size of the revolver to $750 million has been recommended and will occur within the next year.

Q. Did you determine how the results of this analysis would affect PGE's ratings by Moody's and/or S&P?

A. Yes. For Moody's criteria, PGE's liquidity profile would be rated "adequate" in 2021 and 2022. For S&P, PGE would be rated "adequate" in 2021 and 2022 based on its rating criteria.

D. Update of Financial and Accounting Regulation Changes

Q. Are there any recent financial or account regulation changes that will impact PGE?

A. Yes. The Inflation Reduction Act, passed by the United States Congress and signed by the President in August 2022, will likely have future implications for PGE.

Q. How will the Inflation Reduction Act impact PGE?

A. It is PGE's understanding that production tax credits (PTCs) could be monetized. As of this filing that remains unclear as the IRS has not implemented any rules. PGE is aware that the Inflation Reduction Act will likely have a financial impact. However, as the exact impact remains unknown, PGE is not able to make any assumptions or predictions about what those impacts will be.

Q. When is the IRS expected to implement rules associated with the Inflation Reduction Act?

A. PGE is expecting the IRS rulemaking process to begin in 2023, but the full timeframe is currently unknown.

III. Cost of Long-Term Debt

Q. What is PGE's cost of long-term debt?

A. PGE's cost of long-term debt in 2024 is expected to be 4.317%. Confidential PGE Exhibit 1001 presents the amount and the effective cost of PGE's outstanding long-term debt for the test year. This includes existing bond issuances as of February 1, 2023, as well as other bond issuances expected in 2023 and 2024.

Q. How did you calculate the cost of long-term debt for 2024?

A. We included the applicable adjustments to debt as approved in Commission Order No. 22-129 when calculating the amount of debt outstanding. The full amount and cost for each issuance of debt outstanding at year end is included. 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 below summarizes PGE's cost of long-term debt for the 2022 test year.

Table 2
PGE's Cost of Long-Term Debt ($000)

	2024 Forecast
Principal Amount	$3,808,800
Annual Interest Cost	$164,411
Effective Interest Rate	**4.317%**

Q. What future debt issuances did you include in your analysis?

A. We expect to issue up to $200 million in long-term fixed rate debt during 2023 and $190 million in long-term fixed rate debt during 2024 and have included the full amounts in our calculation as our current best estimate.

Q. What is the expected term, coupon rate, and issuance cost for the bonds to be issued in 2023 and 2024?

A. In October 2023, PGE expects to issue a $200 million FMB maturing in 12 years with a coupon rate of 4.88%. In January 2024, PGE currently expects to issue $190 million 15-year FMBs with a coupon rate of 5.03%. We will update our cost of debt as actual terms become available.

Q. How are the estimated coupon rates and issuance costs derived by PGE?

A. The 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 2023 or 2024?

A. Yes. PGE has $80 million of FMBs maturing in 2024.

IV. Cost of Equity

Q. Do you have any conclusions and opinions regarding the appropriate allowed ROE?

A. Yes. The determination of PGE's allowed ROE takes place during uncertain economic and financial conditions due to several economic and industry specific factors. Inflation is at a level not seen in decades, both Treasury bond yields and utility bond yields have been increasing dramatically, and the Federal Reserve is tightening monetary policy. At the same time the electric industry is undergoing substantial changes as, for example, the Oregon State Legislature in 2021 passed a clean energy targets bill that requires electricity providers to reduce greenhouse gas emissions to 80% below baseline emissions by 2030, 90% below baseline emissions by 2035, and 100% below baseline emissions by 2040.[15] These targets will require investments and a change in the manner in which power is procured, thus making the business environment more uncertain. It is important to consider the business risk when evaluating the appropriate ROE for PGE and I address this issue in Section D below.

Based on my analysis of the required ROE for the comparable companies and the business risk of PGE, I find the following ranges for the ROE using two versions of the Discounted Cash Flow (DCF) model, two versions of the Capital Asset Pricing Model (CAPM) as well as the risk premium model, shown in Figure 1.

[15] H.B. 2021, 81st Legislative Assembly, 2021 Regular Session (Oregon 2021); Department of Environmental Quality: Oregon Clean Energy Targets : Action on Climate Change : State of Oregon.

Figure 1
Summary of Reasonable Ranges[16]

	Low End	High End	Midpoint
DCF	8.8%	10.5%	9.7%
CAPM	8.5%	11.5%	10.0%
Risk Premium	10.4%	10.4%	10.4%
Average			10.0%

Based on these results, I find that a reasonable range is 9.7% to 10.4%, which is based on the considerations that (i) it expands the range around the average of the midpoints to include all three midpoints, (ii) it includes results from all three models, and (iii) is consistent with recently allowed ROEs.[17]

Q. How is the remainder of your testimony on cost of equity organized?

A. Section A formally defines the cost of capital and explains the techniques for estimating it in the context of utility rate regulation. Section B discusses conditions and trends in the U.S. capital markets and their impacts on the cost of capital. Section C explains my cost of equity analyses and presents the results. Section D discusses PGE's business risk characteristics and other PGE-specific business risks that are relevant to my recommended allowed ROE. Finally, Section E concludes my testimony with a summary of my recommendations.

Q. Are you sponsoring any exhibits to your direct testimony?

A. Yes, I am sponsoring and have attached the following exhibits.

- Exhibit 1003: Resume of Dr. Bente Villadsen
- Exhibit 1004: Technical Appendix
- Confidential Exhibit 1005: Cost of Equity Estimates

[16] As explained in Section E, these are reasonable ranges and not raw results, which includes both lower and higher figures.

[17] The average allowed ROE in 2022 for integrated electric utilities was 9.72% and the allowed ROEs were in the range of 9.3% to 10.5% (excluding an unusual Vermont matter). Source: S&P Global, Past Rate Cases (2022) as of January 10, 2023. According to the source, no electric rate cases have been decided in 2023 to date and data from early 2022 do not reflect the current interest rate environment.

A. Cost of Capital Principles and Approach

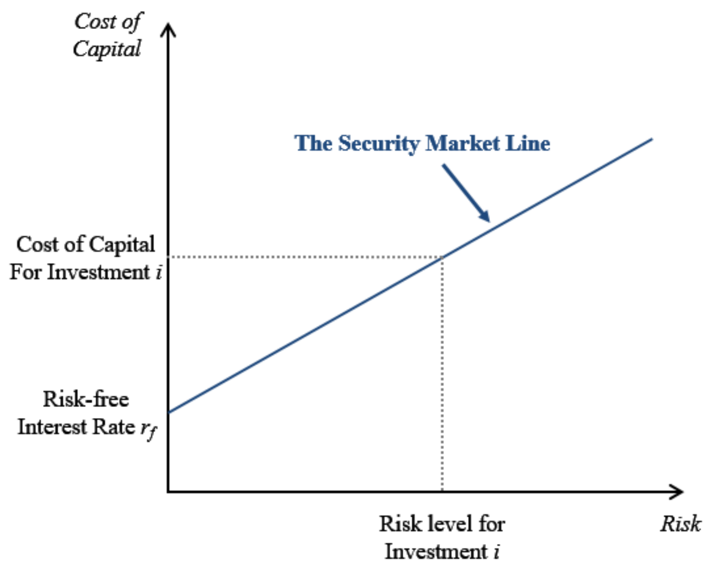
<u>Risk and the Cost of Capital</u>

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 cost of capital is a type of opportunity cost—it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected," as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that can be represented by the "security market risk-return line" or "security market line" for short. The line is depicted in Figure 2 below. The higher the risk, the higher cost of capital required.

Figure 1
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 (and its assets) vary in response to moves in the broader market. In the 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 (decrease) in the market index.

The second category of risk relevant for equity investment depends on how the business enterprise is financed and is called financial risk. Section B below explains how financial risk affects the systematic risk of equity.

Q. What are the guiding principles for determining allowed utility returns?

A. The seminal guidance on this topic was provided by the U.S. Supreme Court in the *Hope* and *Bluefield* cases,[18] which found that:

- The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks;
- 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.[19]

Q. How does the standard for a just and reasonable rate of return relate to the cost of capital?

A. The first component of the *Hope* and *Bluefield* standard, as articulated above, is directly aligned with the financial concept of the opportunity cost of capital.[20] The cost of capital is the rate of return investors can expect to earn in capital markets on alternative investments of equivalent risk.[21] Thus, it is essential to consider the risk factors that affect the potential variability in expected returns, as well as the average level of those returns. In short, the "comparability" of investments and returns must be considered on a risk-adjusted basis.

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[18] *Bluefield Waterworks & Improvement Co. v. Public Service Comm'n of West Virginia et al.*, 262 U.S. 679, 43 S.Ct 675 (1923)., and *Federal Power Commission et al. v. Hope Nat. Gas Co., et al.*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1944).

[19] *Bluefield*, at 680.

[20] 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*, THE BELL JOURNAL OF ECONOMICS AND MANAGEMENT SCIENCE, vol. 3, No. 1, pp:58-97 (1972).

[21] The opportunity cost of capital is also referred to as simply the "cost of capital," and can be equivalently described in terms of the "required return" needed to attract investment in a particular security or other asset (i.e., the level of expected return at which investors will find that asset at least as attractive as an alternative investment).

The impact of risk on investors' required returns is central to the financial concept of the opportunity cost of capital, and to the "comparable investments" and "capital attraction" components of the fair return standard. Put simply, a fair return must be sufficiently attractive to compensate investors for forgoing the opportunity to earn a return from an alternative investment of comparable risk. The return that investors require to compensate for this opportunity cost is the cost of capital. Therefore, a fair allowed return must be at least as high as that available on comparable investments (i.e., it must meet the comparability criteria).

The second component of the fair return standard requires that confidence in the company's financial soundness is maintained. A frequent interpretation of this is that the investors continue to be willing to provide capital, so a solid credit rating is crucial for debt investors and equity investors need to be confident that the company will remain financially on solid footing (e.g., continue dividend payments).

The third component of the fair return standard requires that the allowed return be sufficient to maintain the company's financial integrity, such that its operations are not hampered by inadequate cash flows. This is a necessary component of a fair return, but not a sufficient one, as even a return that provides cash flow adequate to support operations may not be sufficient to attract investment capital in competition with comparably risky alternative investments. Even if an allowed return and deemed equity thickness allow a utility to maintain a high-quality credit profile and raise debt capital on reasonable terms, it does not necessarily ensure that the return on equity—when appropriately accounting for the risk-impact of financial leverage inherent in the regulatory capital structure—is competitive with that available for alternative investments of comparable risk.

Q. What is the relationship between allowed return and the cost of capital?

A. In principle, the allowed return should match the cost of capital provided that the utility in question, PGE, has an opportunity to earn the allowed return and that any deviations are symmetrically around the allowed return / cost of capital. Allowing an inadequate return or having an asymmetric opportunity around that return leads to either the utility or customers losing out. Additionally, I note that while deviations of the expected rate of return on the rate base from the cost of capital may seemingly create a "zero-sum game" so that too high a return results in investor gain and customer losses is simply wrong. In the longer term, inadequate returns are likely to expose customers—and society generally—to risks that cost far more than may be saved in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or new plant and equipment. Without access to investor capital, the company may be forced to forego opportunities to maintain, upgrade, and expand its system in facilities that decrease long-run costs. Indeed, the costs to consumers of an undercapitalized industry can be far greater than any short-run gains from shortfalls in the cost of capital. This is especially true for capital-intensive industries (such as electric utilities).

Q. Please summarize how you considered risk when estimating the cost of capital.

A. To assess the cost of capital for PGE, I start by selecting proxy groups of publicly traded companies that provide regulated utility services. Specifically, I selected a proxy group consisting of electric utilities and supplemented my analysis with a sample of natural gas utilities. Each of the utility proxy groups has a high proportion of regulated assets and revenues with the majority having more than 80% of their assets subject to regulations. They also all have a network of assets that are used to serve end-use customers and they are capital intensive (meaning that each dollar of revenue requires substantial investments in fixed assets). I discuss each sample and the selection process in further detail in Section E.

To arrive at my final ROE recommendation, I consider (i) the range of estimates I derived, (ii) the current economic outlook, (iii) financial risk differences, and (iv) the business risks of PGE relative to that of the proxy samples. Specifically, I consider the fact that PGE's PCAM, unlike that of most electric utilities, has deadbands and that the deadbands result in asymmetric sharing, such that PGE must absorb the first $30 million before sharing excess power costs with customers, while it can retain only $15 million of power cost savings. This design makes it more challenging for PGE to earn its allowed ROE relative to its peers.

<u>Financial Risk and the Cost of Equity</u>

Q. How does capital structure affect the cost of equity?

A. Debt holders 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 DCF models and the CAPM rely on market data to estimate the cost of equity for the proxy companies, so the results reflect the value of the capital that investors hold during the estimation period (market values).

The authorized ROE is applied to the 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 finance their operations with a different debt and equity proportion than the proportion the Commission allows in PGE's rate base. Specifically, the DCF models (and the CAPM) 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 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 using market data for the proxy group companies?

A. The impact of financial risk is taken into account in an analysis of cost of equity using market-based models such as the DCF and CAPM in several manners. One way is to determine the after-tax weighted average cost of capital for the proxy group using the equity and debt percentages as the weight assigned to the cost of equity and debt. Financial theory holds that for a given level of business risk, the weighted average cost of capital is constant over a broad set of capital structures, i.e., the weighted average cost of capital is the same at, for example, 55% and 45% equity, as the cost of equity increases as the percentage of equity decreases. I estimate the weighted cost of capital for each utility in the proxy group based on that utility's capital structure. I then evaluate the average weighted cost of capital across the proxy group. Once the weighted cost of capital is determined for the proxy group, I can then determine the cost of equity that is required at PGE's regulatory capital structure. This approach assumes that the after-tax weighted average cost of capital is constant for a range that spans the capital structures used to estimate the cost of equity and the regulatory capital structure.

A second approach was developed by Professor Hamada, who estimated the cost of equity using the CAPM and made comparisons between companies with different capital structures using beta. Specifically, in the Hamada approach, I use the estimated beta to calculate what beta would be associated with a 100% equity financed firm to obtain a so-called all-equity or assets beta and then re-lever the beta to determine the beta associated with the regulatory capital structure. This requires an estimate of the systematic risk associated with debt (i.e., the debt beta), which is usually quite small. In Exhibit 1004, I provide additional technical details regarding the methods that can be used to account for financial risk when estimating the cost of capital.

Q. Can you provide a numerical illustration of how the cost of equity changes, all else equal, when the degree of leverage changes?

A. Yes. I constructed a simple example below, where only the leverage of a company varies. I assumed the return on equity is 11.00% at a 50% equity capital structure and determine the return on equity that would result in the same overall return if the percentage of equity in the capital structure were reduced to 45%.

Figure 2
Illustration of the Impact of Financial Risk on ROE

		Company A (50% Equity)	**Company B** (45% Equity)
Rate Base	[a]	$1,000	$1,000
Equity	[b]	$500	$450
Debt	[c]	$500	$550
Total Cost of Capital (8%)	[d] = [a] x 8%	**$80**	**$80**
Cost of Debt (5%)	[e] = [c] x 5%	$25	$28
Equity Return	[f] = [d] - [e]	$55	$53
Rate of Return on Equity (ROE)	[g] = [f] / [b]	**11.00%**	**11.67%**

Figure 3 above illustrates how financial risk[22] affects returns and the ROE. The overall return remains the same for Companies A and B at $80. However, Company B with the lower equity share and higher financial leverage must earn a higher percentage ROE in order to maintain the same overall return. This higher percentage allowed ROE represents the

[22] Financial risk is risk that a company has due to its capital structure; specifically, the higher a company's debt, the larger the financial risk.

increased risk to equity investors caused by the higher degree of leverage. Importantly, regardless of the equity percentage, customers will pay $80 in capital costs – the only difference between the two companies is how that $80 is sourced between equity and debt holders. The principle illustrated in Figure 3 is an example of the first adjustment I performed to account for differences in financial risk when conducting estimates of the cost of equity applicable to PGE.

Q. Does this approach apply to the risk premium analysis?

A. Yes, to the extent that there are differences between the capital structures of the companies used to determine the benchmark ROE and PGE, I need to consider whether we are comparing apples to apples. However, because the allowed ROE is usually applied to book value capital structures, it is the book value capital structure that is relevant for the risk premium method. I note, however, that in 2022, the average and median equity percentages allowed for integrated electric utilities were 49.6% and 52%,[23] respectively, so PGE's requested equity percentage is in line with what has commonly been allowed. I, therefore, do not consider financial leverage for the risk premium model's results.

<u>Approach to Estimating the Cost of Equity</u>

Q. Please describe your approach to determining the cost of equity for PGE.

A. As stated above, the standard for establishing a fair rate of return on equity requires that a regulated utility be allowed to earn a return equivalent to what an investor could expect to earn on an alternative investment of equivalent risk. Therefore, my 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.

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[23] S&P Capital IQ, "Rate Case History," accessed January 10, 2023.

Because certain models require market data, my consideration of comparable companies is restricted to those that have publicly traded stock. As noted above, I selected a group of integrated electric utilities. I applied two versions of the DCF model and two versions of the CAPM and ECAPM[24] to the samples.

I also perform an analysis of historical allowed ROEs for 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.

B. Capital Market Conditions and the Cost of Capital

Q. What do you cover in this section?

A. In this section, I address recent changes in capital market conditions, the increased volatility in equity and debt markets, and how these factors affect the cost of equity and its estimation. Specifically, I address (i) inflation developments and expectations, (ii) interest rate development, and (iii) investors' perception of the market risk premium. Investors' perception of PGE-specific risks are discussed in Section D.

Q. Why do you discuss capital market conditions in testimony aimed at 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, inputs to the DCF models are affected by the economy as economic growth will affect utility growth rates and stock prices.

[24] Empirical Capital Asset Pricing Model (ECAPM). Discussed further in Section C.

Consequently, the capital market developments affect the growth rates, dividend yield, and assessment of estimates' reasonableness.

Furthermore, the risk-free rate is an input to the CAPM and risk premium model, so that recent and expected developments in government bond yields are important to assess the validity of any measure of the risk-free rate. Similarly, the market equity risk premium ("MRP") (e.g., volatility and changes in investors' risk perceptions) are vital for accurate determinations of the ROE.

Q. Can you provide a summary of recent events that have impacted capital market conditions?

A. Economic activity rebounded in 2021 with real Gross Domestic Product (GDP) growing by 5.7%,[25] but inflation started increasing. By March 2022, the Consumer Price Index (CPI)—a common measure of inflation—increased on annual basis by 7.9%, which was the largest CPI reading increase since January 1982.[26] As of December 2022, the inflation rate was 6.5%. In early 2022, geopolitical tensions increased following the Russian invasion of Ukraine which put further strain on global economic activity. In response, the U.S. Federal Reserve began tightening monetary policy. On March 16, 2022, the Federal Reserve increased its policy rate for the first time since the start of the pandemic[27] and ended up increasing the Federal Funds Rate seven times for a total of 450 basis points in 2022 and early 2023 as shown in Figure 4 below.

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[25] U.S. Bureau of Economic Analysis, Press Release BEA 22-05, Gross Domestic Product, Fourth Quarter and Year 2021 (Second Estimate), February 24, 2022, available at: https://www.bea.gov/news/2022/gross-domestic-product-fourth-quarter-and-year-2021-second-estimate and CPI Home : U.S. Bureau of Labor Statistics (bls.gov)

[26] U.S. Bureau of Labor Statistics, Press Release USDL 22-0415, Consumer Price Index News Release, March 10, 2022, available at: https://www.bls.gov/news release/archives/cpi 03102022 htm and https://www.bls.gov/regions/mid-atlantic/data/consumerpriceindexhistorical us table.htm

[27] U.S. Federal Reserve, Board of Governors of the Federal Reserve System, Federal Reserve Press Release, March 16, 2022, available at: https://www federalreserve.gov/monetarypolicy/files/monetary20220316a1.pdf

Figure 3
Federal Reserve Policy Rate Changes[28]

FOMC Meeting	Change (bps)	Federal Funds Rate
March 16, 2020	-100	0.0% - 0.25%
March 17, 2022	+25	0.25% - 0.50%
May 5, 2022	+50	0.75% - 1.00%
June 16, 2022	+75	1.50% - 1.75%
July 28, 2022	+75	2.25% - 2.50%
September 22, 2022	+75	3.00% - 3.25%
November 3, 2022	+75	3.75% - 4.00%
December 15, 2022	+50	4.25% - 4.50%
February 1, 2023	+25	4.50% - 4.75%

The Federal Reserve has also started to scale back quantitative easing at the Federal Open Markets Committee ("FOMC") meetings.

Regardless, CPI remains near multi-decade highs. In June 2022, CPI increased to 9.1%—the largest increase since November 1981.[29] Most recently, the CPI has declined somewhat to 6.5% but remains well above the Federal Reserve's target of 2% (on average).[30] The persistently high inflation has maintained pressure on the Federal Reserve to use monetary policy to combat inflation. At the December FOMC press conference, Chairman Powell stated:

> Over the course of the year, we have taken forceful actions to tighten the stance of monetary policy. We have covered a lot of ground, and the full effects of our rapid tightening so far are yet to be felt. Even so, we have more work to do.
>
> With today's action, we have raised interest rates by 4-1/4 percentage points this year. We continue to anticipate that ongoing increases in the target range for the federal funds rate will be appropriate in order to attain a stance of monetary policy that is sufficiently restrictive to return inflation to 2 percent over time. Over the course of the year, financial conditions have tightened significantly in response to our policy actions. Financial conditions fluctuate in the short term in response to

[28] *Ibid*.
[29] U.S. Bureau of Labor Statistics, "Consumer Price Index News Release," USDL-22-1470, July 13, 2022, available at: https://www.bls.gov/news release/archives/cpi 07132022.htm
[30] U.S. Bureau of Labor Statistics, "Consumer Price Index News Release," USDL-22-2304, December 13, 2022, available at: https://www.bls.gov/news release/archives/cpi 12132022 htm and https://www.bls.gov/regions/mid-atlantic/data/consumerpriceindexhistorical us table.htm

> many factors, but it is important that over time they reflect the policy restraint we are putting in place to return inflation to 2 percent. We are seeing the effects on demand in the most interest-sensitive sectors of the economy, such as housing. It will take time, however, for the full effects of monetary restraint to be realized, especially on inflation. In light of the cumulative tightening of monetary policy and the lags with which monetary policy affects economic activity and inflation, the Committee decided to raise interest rates by 50 basis points today, a step down from the 75-basis point pace seen over the previous four meetings. Of course, 50 basis points is still a historically large increase, and we still have some ways to go.[31]

Tightening monetary policy along with increasing economic and financial risks have caused interest rates to rise. Yields on 10-year U.S. Government Bonds have more than doubled from 1.52% at the end of 2021 to about 3.55% as of January 30, 2023.[32] In addition, real GDP declined by 1.6% in Q1 2022 – the first quarterly decline since the onset of the pandemic in Q2 2020.[33] Real GDP also decreased by 0.6% in Q2 2022.[34] Two consecutive declines in real GDP meets the commonly used definition of a technical recession; however, the National Bureau of Economic Research's Business Cycle Dating Committee has not yet officially announced a recession. Real GDP increased by 2.9% in Q3 2022.[35] The Federal Reserve projects that real GDP will grow by only 0.5% in 2022.[36]

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[31] U.S. Federal Reserve, "Transcript of Chair Powell's Press Conference," December 14, 2022, available at: https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20221214.pdf

[32] Board of Governors of the Federal Reserve System (US), Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity, Quoted on an Investment Basis [DGS10], retrieved from FRED, Federal Reserve Bank of St. Louis; available at: https://fred.stlouisfed.org/series/DGS10

[33] U.S. Bureau of Economic Analysis, "Gross Domestic Product (Third Estimate), GDP by Industry, and Corporate Profits (Revised), 2nd Quarter 2022 and Annual Update," BEA 22-49, September 29, 2022, available at: https://www.bea.gov/news/2022/gross-domestic-product-third-estimate-gdp-industry-and-corporate-profits-revised-2nd

[34] *Ibid*.

[35] U.S. Bureau of Economic Analysis, "Gross Domestic Product (Second Estimate), Corporate Profits (Preliminary Estimate), Third Quarter 2022," BEA 22-58, November 30, 2022, available at: https://www.bea.gov/sites/default/files/2022-11/gdp3q22_2nd.pdf

[36] U.S. Federal Reserve, "Summary of Economic Projections," December 14, 2022 (the most recent available); available at: https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20221214.pdf

Q. What are the expectations going forward?

A. The extent and length of the economic and financial impacts from persistently high inflation, the monetary policy response to combat inflation, as well as ongoing supply chain issues and the war in Ukraine, are unknown. However, inflation has persisted at levels not seen in decades. These factors are putting downward pressure on the economy, resulting in two consecutive declines in real GDP growth in 2022 (before increasing in Q3 2022). At the December meeting, the Federal Reserve revised its real GDP forecast for 2023 from 1.2% (September projection) to 0.5% (December projection).[37] Notably, the Federal Reserve's projection was 2.2% in March 2022 —so 170 basis points higher in March than in December.[38]

The Federal Reserve also anticipates further tightening of monetary policy and confirmed its commitment to reaching an inflation of about 2% in its January meeting.[39] The Federal Funds Rate projection for 2023 increased from 4.6% (September projection) to 5.1% (December projection).[40] Despite this, the Federal Reserve also forecasts inflation to further increase in 2023 (3.1% September projection versus 3.5% December projection) and 2024 (2.3% September projection versus 2.5% December projection).[41] However, Core PCE (the Federal Reserve's preferred inflation measure) was recently measured at 5.0% in October 2022 (latest available data), exceeding the Federal Reserve's December projection of 4.8% in

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[37] *Ibid.*
[38] U.S. Federal Reserve, "Summary of Economic Projections," March 16, 2022, available at: https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20220316.pdf
[39] Federal Reserve Issues FOMC Statement, February 1, 2023.
[40] U.S. Federal Reserve, "Summary of Economic Projections," December 14, 2022, https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20221214.pdf
Note: The March 2022 projection was 2.8%.
[41] *Ibid*. Based on the Core PCE inflation indicator.

2022.[42] Taken together, economic indicators and the projections from the Federal Reserve suggest that interest rates will continue to rise.

In November 2022, Moody's revised its outlook for the U.S. regulated utility sector to negative due to rising inflation, interest rates, and natural gas prices, which they expect will persist into 2023.[43] Moody's raises the concern that these macroeconomic effects could affect utilities' ability to promptly recover costs, absent regulatory support. Fitch Ratings has similarly raised concerns about the outlook for utilities and also cited inflation, interest rate increases and commodity costs.[44]

Q. How does this impact the cost of equity estimation for PGE?

A. It is important to remember that the cost of equity established for PGE in this proceeding is expected to be in effect during the future rate period. The analysis and recommendations should reflect the current expectations of market conditions.

<u>Inflation Expectations and Impact</u>

Q. Why is inflation relevant to the return of PGE?

A. The return on equity that is being determined now is expected to be in effect for at least a year or two, so PGE will be exposed to the development in inflation throughout this period. Historically, inflation and the cost of equity have moved in the same direction. For example, in the late 1980s and early 1990s when inflation was high, allowed ROEs were above 12%.

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[42] Bureau of Economic Analysis, Press Release 22-59, "Personal Income and Outlays, October 2022," December 1, 2022, available at: https://www.bea.gov/news/2022/personal-income-and-outlays-october-2022
[43] Robert Walton, *Moody's Adopts Negative Outlook for Regulated Utility Sector, Warns on Gas Prices, Economy and Cost Recovery*, UTILITY DIVE, November 11, 2022, available at: https://www.utilitydive.com/news/moodys-adopts-negative-outlook-for-regulated-utility-sector-warns-on-gas/636357/
[44] Fitch Ratings, "Deteriorating Outlook for North American Utilities, Power & Gas in 2023," December 7, 2022.

Q. What are recent indicators of the growth of inflation for the US economy?

A. As of December 9, 2022, Blue Chip Economic Indicators' (BCEI) economists forecast that inflation will remain high into 2023, consistent with the projections from the Federal Reserve (discussed above).[45] BCEI forecasts the consumer price index in 2022 will be 8.0% and decline to 4.0% in 2023 in response to the Federal Reserve's monetary tightening.[46] The January 2023 expectations are similar in that the 2023 expectations for the CPI are now 3.8% as the monetary tightening is expected to take effect.[47]

As shown in Figure 5 below, the inflation as measured by the CPI is currently higher than levels seen in 40 years, according to the Bureau of Labor Statistics.[48] Rising inflation is introducing new uncertainties to the financial markets and increasing the return required by investors to hold risky assets. Specifically, because the allowed ROE is a nominal return, an increase in inflation would result in a reduction in the value of any allowed ROE. If rising inflation trends persist, utilities will face increasing cost recovery risks to the extent that actual costs exceed those measured by a utility during its test period.

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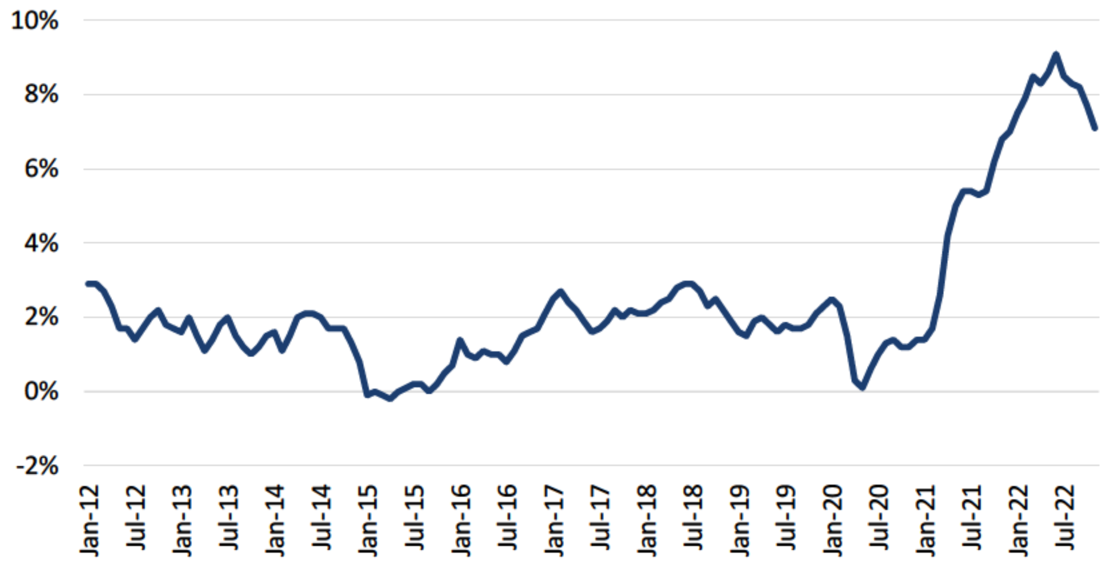
[45] Wolters Kluwer, Blue Chip Economic Indicators, Vol. 47, No. 12, December 9, 2022.
[46] *Id.,* at pp. 2-3.
[47] Blue Chip Economic Indicators, January 10, 2023, p. 2
[48] U.S. Bureau of Labor Statistics, Press Release USDL 22-1470, "Consumer Price Index News Release," July 13, 2022, available at: https://www.bls.gov/news release/archives/cpi 07132022.htm

Figure 4
Annual Change in Consumer Price Index (All Urban Consumers)[49]



Interest Rates

Q. How do interest rates affect the cost of equity?

A. The current interest rate environment 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.[50] 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. Therefore, the allowed fair return on equity for PGE should reflect the future interest rate environment, specifically the environment at the time the rates being set in this proceeding will be in effect.

[49] Bureau of Labor Statistics, CPI for All Urban Consumers, updated through 12/12/2022
[50] *See* Figure 2.

Q. What are the relevant developments regarding interest rates?

A. At the end of December 2022, the 20-year Treasury bond yield was 3.87% and the Baa utility bond yield was 5.32%. In comparison, the 20-year yield was 2.99% and the Baa utility bond yield was 4.56% in April 2022, when PGE's last rate case was decided.[51] This is an increase of about 90 and 70 basis points in the Treasury and utility bond yield, respectively.[52] Similarly, yields on 20-year U.S Government bonds were at 2.99% in April 2022 and are at the time of estimation (November 2022) 123 basis points higher at 4.22%.[53]

Looking forward, treasury bonds are forecasted to decline slightly in 2023 and then decrease further in 2024, which is depicted in Figure 6 below. BCEI's December 2022 edition forecasts that the yield on 10-year treasury bonds will increase to 3.8% in 2023,[54] and then decrease to 3.3% in 2024.[55] Since the risk-free rate is an input to several cost of equity estimation models, the relationship between current and forecasted risk-free rates is an important consideration. As can be seen from Figure 6 below, interest rate forecasts have not been able to follow the actual interest rates up.

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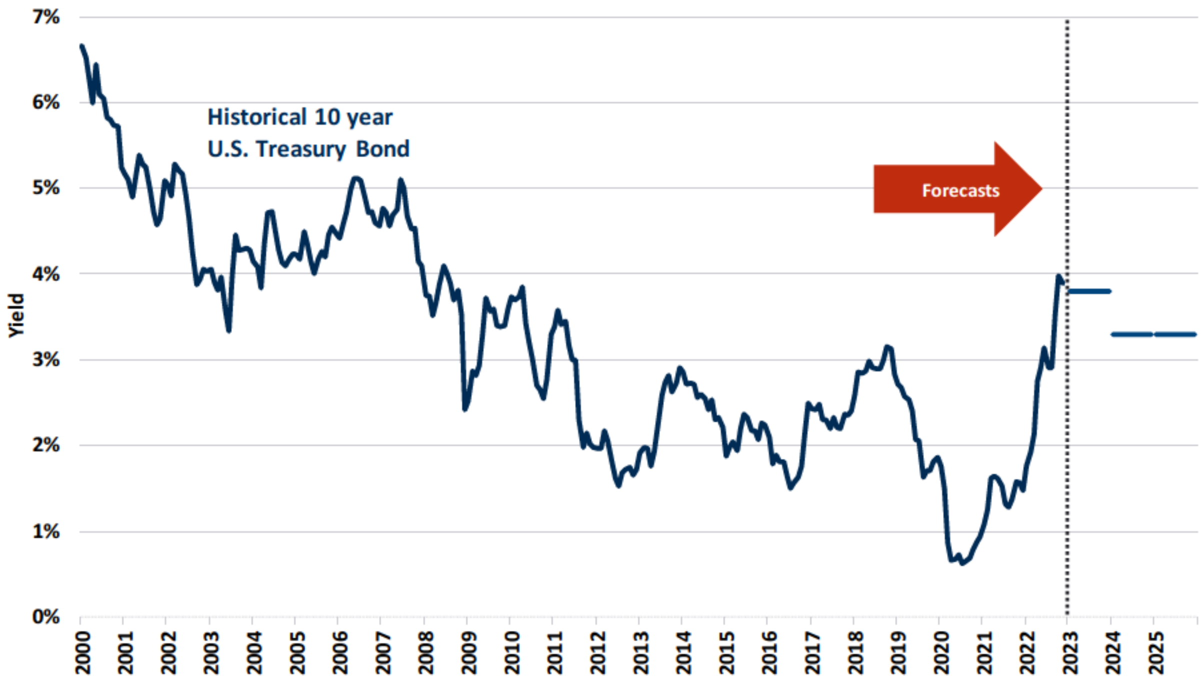
[51] According to S&P Global Intelligence, "RateCase History," as of January 11, 2023, UE 394 was settled on April 22, 2022.
[52] Federal Reserve based on 20-year yield accessed January 10, 2023; Board of Governors of the Federal Reserve System (US), Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity, Quoted on an Investment Basis [GS10], retrieved from FRED, Federal Reserve Bank of St. Louis; available at: https://fred.stlouisfed.org/series/GS10, February 10, 2023.
[53] Federal Reserve based on 20-year yield accessed January 10, 2023, Board of Governors of the Federal Reserve System (US), Market Yield on U.S. Treasury Securities at 20-Year Constant Maturity, Quoted on an Investment Basis [GS20], retrieved from FRED, Federal Reserve Bank of St. Louis; available at: https://fred.stlouisfed.org/series/GS20 February 10, 2023.
[54] Wolters Kluwer, Blue Chip Economic Indicators, Vol. 47, No. 12, December 9, 2022, p.3.
[55] Wolters Kluwer, Blue Chip Economic Indicators, Vol. 47, No. 10, October 10, 2022, p. 14.

Figure 5
Historical and Projected Ten-Year Treasury Bond Yields[56]



Yield Spreads

Q. Why are bond yield spreads relevant to your cost of equity analysis?

A. Bond yield spreads (also called credit spreads) reflect the premium that investors demand to hold debt securities (specifically corporate or utility bonds) that are not risk-free. Analogously, the Market Risk Premium (MRP)—which is a key input to the CAPM cost of equity estimation—represents the risk premium that investors require to hold equities rather than risk-free government bonds.

If bond yields are influenced to some extent by the same underlying market factors that drive the systematic risk premium for equities, shifts in directly observable credit spreads can assist with inference about changes in the MRP, which itself must be estimated.[57]

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[56] Historical data from Bloomberg. Forecasts from Wolters Kluwer Blue Chip Economic Indicators October and December 2022.

[57] This is the same issue as in cost of capital estimation more generally: the cost of debt can often be directly observed in the form of market bond yields, whereas the cost of equity must be estimated based on financial models.

More specifically, if both credit spreads and equity premiums are determined in part by the general premium required by investors for bearing systematic risk, then an increase in credit spreads may indicate an increase in the forward-looking MRP.

Q. How does the current spread between utility and U.S. Government Bond yields compare to historical spreads?

A. As interest rates declined, the spread between A-rated utility bonds and government bond yields increased. Currently, A-rated utility bond spreads over Government Bond yields is 1.43%.[58] This compares to a long-term historic average spread of 0.96% prior to the financial crisis.[59] As the spread difference is limited and plausibly will normalize over the next couple of years.[60] While I conservatively do not take any portion of the elevation in yield spread into account in my analysis, I do consider it implicit evidence that the return investors require to hold assets that are not riskless is higher than previously.

<u>Risk Premiums</u>

Q. How do risk premiums affect the cost of equity?

A. Risk premiums indicate 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 premium magnitudes in addition to the yield spreads discussed above. For example, indicators such as stock market volatility (i.e., VIX) provide insights into the risk premium required by investors. SKEW provides a useful indicator of volatility over the next 12 months whereas, the MRP measures the compensation required to

[58] *See* Exhibit 1004, 15-day average from November 10, 2022, to November 30, 2022.
[59] *Ibid*. Average from December 1993 to 2007.
[60] Currently (mid-December 2022), the yield on 3-month and 2-year Treasuries is higher than those on 10-, 20-, or 30-year Treasuries, so the relationships between the yields is not increasing in the horizon of the security as is commonly the case.

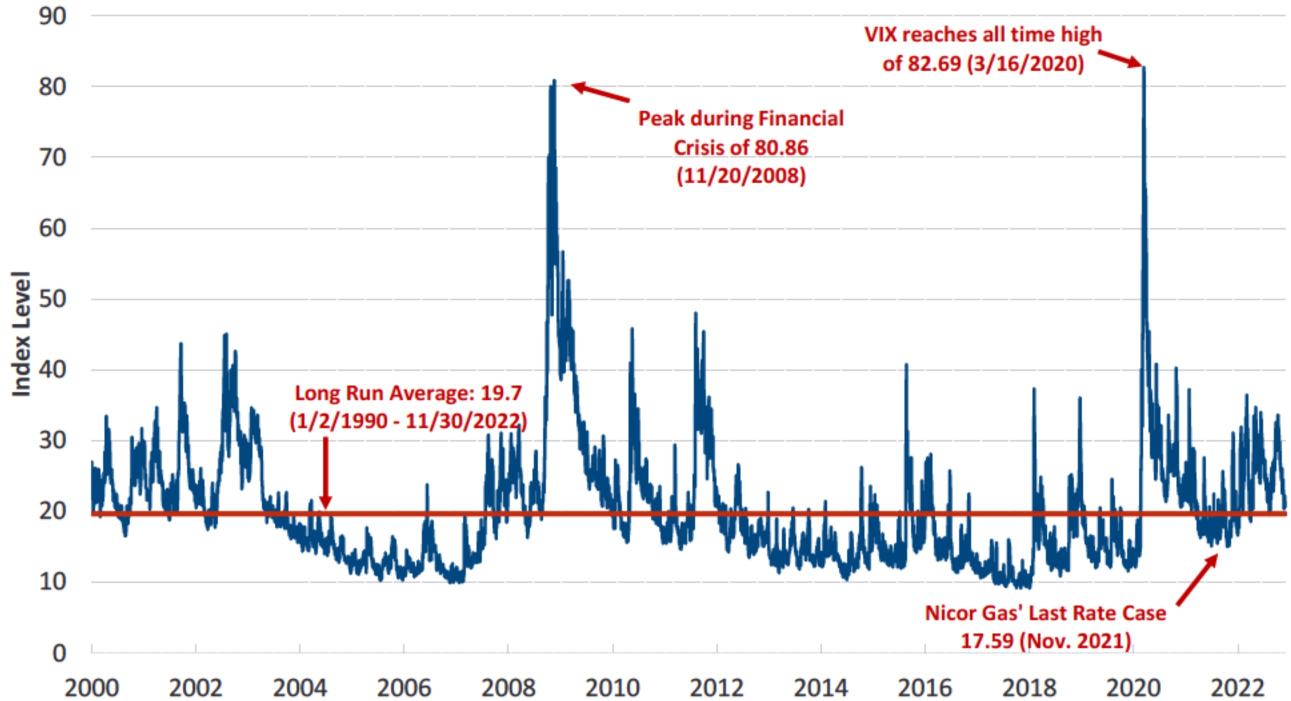
hold a security over a long investment horizon, such as when rates set forth in this proceeding are expected to be in effect. For this reason, the forecasted MRP needs to be taken into consideration when determining the cost of equity in this proceeding. Several financial models used to estimate the cost of equity (including the CAPM and the Implied Risk Premium model) use a risk premium as one of the inputs in a manner that dictates the cost of equity increases with the risk premium. Therefore, developments in the risk premium are important.

Q. What is the current evidence regarding market volatility?

A. During the early months of the COVID-19 pandemic, financial markets became extremely volatile as shown in common near-term volatility measures, such as the VIX, which is frequently referred to as the market's fear index. As shown in Figure 7 below, the VIX reached an all-time high of 82.7 on March 16, 2020, which was higher than the peak of 80.86 during the Financial Crisis. Since then, VIX has remained elevated for some time and then returned to its long-term average of 19.7.[61]

[61] Bloomberg data as of January 2023.

Figure 6
VIX: 2000 through December 2022

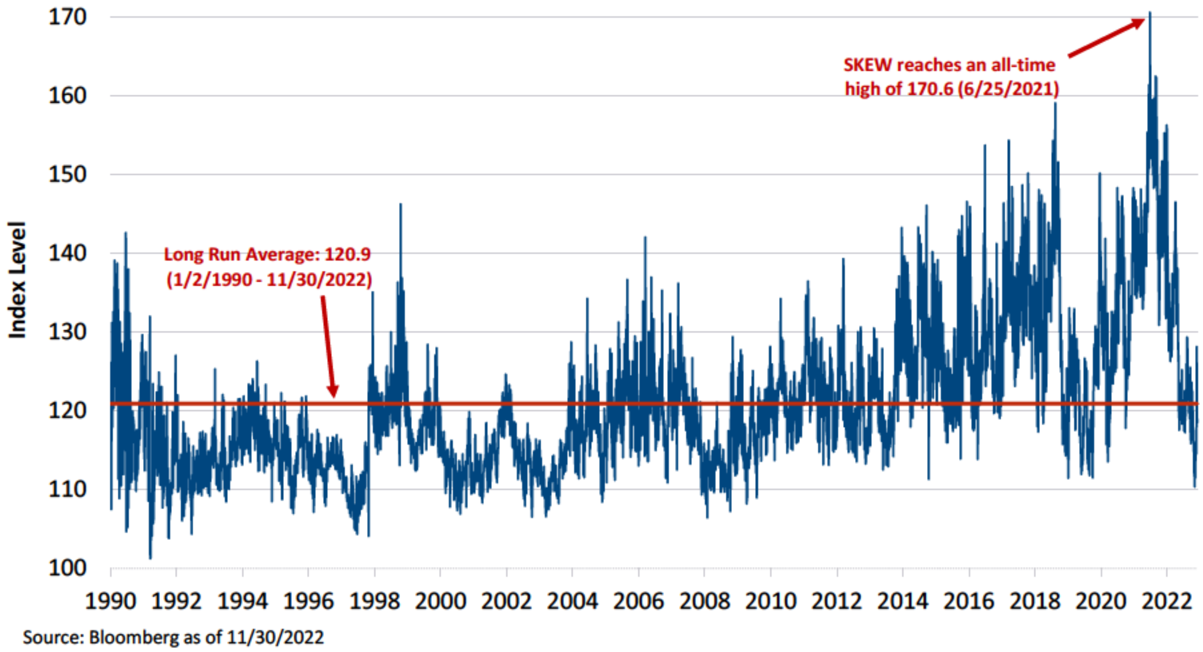


Source: Bloomberg as of 11/30/2022

Similarly, the SKEW index, which measures the market's willingness to pay for protection against negative "black swan" stock market events (i.e., sudden substantial downturns),[62] shows that investors are cautious. A SKEW value of 100 indicates outlier returns are unlikely, but as the SKEW increases, the probability of outlier returns becomes more significant. Figure 8 below shows the SKEW values since 1990.

[62] *See* https://www.cboe.com/us/indices/dashboard/skew/.

Figure 7
SKEW: 1990 through December 2022



As both the VIX and SKEW measures are forward-looking, the variability in VIX and SKEW shows that investors expect volatility to continue (for at least a year) but are cautiously optimistic about investing in equity.

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 for taking on risk. As previously illustrated in Figure 2, the riskier the investment, the larger the risk premium investors will require.

The Market Risk Premium (MRP) 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 investors,[63] 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 estimate the cost of equity using the CAPM and other risk-positioning models.

Q. Please explain the current evidence related to the MRP.

A. The heightened volatility increased the premium that investors require to hold risky assets, especially when measured utilizing forward-looking methodologies that estimate expected market returns with reference to current dividend yields. Following the onset of the pandemic, Bloomberg's forward-looking estimate of the MRP reached a high of 9.84% in March 2020.[64] More recently, Bloomberg's MRP has decreased due to rising interest rates driving down company growth rates. Importantly, the forecasted MRP and the risk-free rate have historically been somewhat offsetting, so the expected return on equity is more stable. Currently, Bloomberg forecasts an MRP of 5.00% over the 10-year Treasury bond yield.[65]

The relatively low forecast for the MRP is inconsistent with the increase in yield spread (currently 143 basis points versus a historical average of 96 basis points), increased market volatility, and the FERC-methodology based MRP of 7.5% to 9.1%.[66] Thus, the Bloomberg forecast is very conservative relative to the approach taken by FERC.

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[63] 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.

[64] Bloomberg, as of December, 2022, measured over a 10-year government bond yield.

[65] *Ibid*., measured over a 10-year government bond yield.

[66] Based on the FERC Methodology for MRP using IBES and Value Line data, respectively, as of November 30, 2022, and measured relative to a 30-year U.S. Government Bond Yield. The FERC MRP is 7.2% to 8.8% measured relative to a 20-year U.S. Government Bond Yield.

Q. Please summarize how the economic developments discussed above have affected the return on equity that investors require.

A. Utilities rely on investors in capital markets to provide funding to support their capital expenditure programs and efficient business operations. Investors consider the risk-return tradeoff in choosing how to allocate their capital among different investment opportunities. It is therefore important to consider how investors view the current economic conditions, including the plausible developments in the risk-free rate and the growth in the U.S. GDP.

These investors have been dramatically affected by the ongoing market uncertainty and continue to be exposed to high inflation, supply chain constraints, market volatility and the effects of the ongoing war in Ukraine. As PGE is expected to be compensated on the equity component of its rate base, the same factors would affect PGE's equity.

Overall, the state of U.S. capital markets indicates that we are experiencing the highest levels of inflation since the stagflation of the late 1970s to early 1980s. We have entered a period of rising interest rates, which are expected to continue to rise to combat increasing inflation, and we have recently witnessed market volatility in the U.S. equities market that reflects the uncertainty of the macroeconomic environment we are facing. As an example, in November 2022, Moody's lowered its outlook for the U.S. regulated utility sector to negative, warning that high natural gas prices, inflation and rising interest rates could mean a struggle to promptly recover costs. Moody's recently downgraded the outlook for U.S. regulated utilities to negative as a result of rising inflation, interest rates, and energy prices. Taken together, these facts indicate that an increase in the allowed ROE and that the recommended ROE of 9.8% for PGE is warranted to compensate PGE's investors for the systematic risk that they are currently and expected to be exposed to while the allowed ROE is in place. Importantly, if inflation remains as high as it has been recently, a nominal ROE of 9.8% may not be sufficient.

C. Approach to Calculating the Cost of Equity

<u>Proxy Group Selection</u>

Q. Why do you select a proxy group to estimate PGE's cost of equity?

A. Because the cost of equity is determined in financial markets, I use financial market data to estimate the cost of equity. Specifically, I use publicly traded companies as benchmarks for PGE's cost of equity. For statistical confidence purposes, I need a sufficient number of observations to be confident that I have a reasonable result.

Q. How do you identify sample companies of comparable business risk to PGE?

A. PGE is a regulated electric utility engaged in electric distribution, transmission, and generation. As further discussed in Section D, the business risks associated with PGE include the specific characteristics of its service territory, the regulatory environment in which the provider of these services operates, and technological changes. Consequently, it is not possible to identify publicly traded sample companies that replicate every aspect of PGE's risk profiles. However, ensuring that the sample companies have their business operations concentrated in similar lines of business and/or business environments is an appropriate starting point for selecting a proxy group of comparable risk to the target companies.

To this end, I select a sample of integrated electric utilities, which have a high percentage of regulated assets. The proxy companies are similar to PGE in that they are regulated by state utility commissions, provide customers a product through a network of assets, and rely on substantial capital to provide service.

The proxy group used to assess the cost of equity for PGE must be regulated because regulation tends to place substantial requirements and also protections on the companies. I also believe the physical characteristics of the industry—for example, network, capital intensive, serving different customer groups (residential, commercial, industrial)—are characteristics of PGE and each of the selected proxy utility companies. The network characteristic implies that assets cannot readily be employed in a different capacity, capital intensity affects the operating risks through the split between fixed and variable costs, and customer composition affects the demand risk. The sample companies, to a varying degree, are subject to federal and state initiatives to combat carbon emissions.

Q. Please summarize how you selected the samples.

A. To identify companies suitable for inclusion in the Electric sample, I started with Value Line's list of publicly traded companies classified as electric utilities (Central, East, or West). Next, I reviewed business descriptions, financial reports, and Edison Electric Institute's description of these companies and eliminated any companies that had less than 50% of their assets dedicated to regulated utility activities in the electric industry.

Within this group of companies, I applied further screening criteria to eliminate companies that have had recent significant events that could affect the market data necessary to perform cost of capital estimation. Specifically, I identified companies that have recently cut their dividends or engaged in substantial merger and acquisition (M&A) activities.[67] I eliminated companies with dividend cuts because the announcement of a cut may produce disturbances in the stock prices and growth rate expectations in addition to potentially being a signal of

[67] Relative to Docket No. UE 335, I eliminated DTE Energy due to its divesture of pipeline assets and included Dominion, whose divesture of pipeline assets is now in the past. I also eliminated distribution only companies.

financial distress. I eliminated companies with significant M&A activities 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. For example, a utility's stock price will commonly jump upon the announcement of an acquisition to match the acquirer's bid.

Further, I require that companies have an investment grade credit rating and a market capitalization of more than $300 million (i.e., not a micro-cap) for liquidity purposes. A final, and fundamental, requirement is that the proxy companies have the necessary data available for estimation.

Q. What are the characteristics of the Electric Sample?

A. The final proxy group consists of 26 electric utilities listed in Figure 9.

All electric utilities are engaged in the distribution, transmission and generation of electricity and are on average highly regulated (more than 80% of assets are regulated). The sample companies have a mix of residential, commercial, and industrial customers and all are regulated.

Figure 9 reports the electric utilities' annual revenues for the most recent four quarters, as of Q3 2022, and also the market capitalization, credit rating, beta, and analyst growth rate estimates. It also includes a categorization of regulated (R) or mostly regulated (MR) based on the percentage of each utilities' assets that are devoted to regulated activities.[68] The annual revenue as well as the market capitalization was obtained from Bloomberg. Betas are 5-year weekly adjusted historical betas obtained from Value Line. The S&P credit rating is as reported by Bloomberg. Lastly, the long-term (3- to 5-year) earnings per share growth

[68] The percentage of regulated assets is based on EEI, "2021 Financial Review," p. 30.

estimate for each company is a weighted average between estimates from Thomson Reuters and Value Line.

Figure 8
Electric Utility Proxy Group

Company	Annual Revenue (Q3 2022) ($MM)	Regulated Assets	Market Cap. (Q3 2022) ($MM)	Value Line Beta	S&P Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	$1,544	MR	$3,223	0.90	BBB	7.4%
Alliant Energy	$4,073	R	$14,900	0.85	A-	5.6%
Amer. Elec. Power	$18,820	R	$50,174	0.75	A-	6.1%
Ameren Corp.	$7,456	R	$23,093	0.85	BBB+	6.3%
Avista Corp.	$1,632	R	$2,867	0.90	BBB	7.1%
Black Hills	$2,323	R	$4,823	0.95	BBB+	5.8%
CMS Energy Corp.	$8,351	R	$18,908	0.80	BBB+	7.8%
CenterPoint Energy	$8,924	R	$19,709	1.15	BBB+	2.7%
Dominion Energy	$16,141	R	$65,077	0.80	BBB+	6.3%
Duke Energy	$28,023	R	$79,708	0.85	BBB+	5.6%
Edison Int'l	$16,535	R	$24,902	0.95	BBB	5.6%
Entergy Corp.	$13,214	R	$22,841	0.95	BBB+	6.4%
Evergy Inc.	$5,702	R	$15,066	0.90	A-	5.0%
Exelon Corp.	$24,041	MR	$41,627	n/a	BBB+	6.6%
IDACORP Inc.	$1,397	R	$5,412	0.80	BBB	4.0%
MGE Energy	$687	R	$2,666	0.70	AA-	2.9%
NextEra Energy	$19,838	MR	$167,556	0.95	A-	9.3%
NorthWestern Corp.	$1,400	R	$3,042	0.90	BBB	4.7%
OGE Energy	$3,245	R	$8,013	1.05	BBB+	5.8%
Otter Tail Corp.	$1,492	R	$2,824	0.85	BBB	na
Pinnacle West Capital	$4,114	R	$8,127	0.90	BBB+	1.5%
Public Serv. Enterprise	$9,717	MR	$31,573	0.90	BBB+	5.7%
Sempra Energy	$14,828	R	$51,565	0.95	BBB+	5.2%
Southern Co.	$27,999	R	$82,014	0.90	BBB+	7.0%
WEC Energy Group	$9,241	R	$31,324	0.80	A-	6.2%
Xcel Energy Inc.	$14,612	R	$39,245	0.80	A-	6.2%
Electric Sample	$10,206		$31,549	0.88	BBB+	5.7%

Compared to PGE, the Electric Sample has the same credit rating,[69] but the average sample company is larger than PGE, which had 2021 annual revenues of $2,396 million and according to Value Line, the consolidated company has a target growth rate of 5% to 6%.[70]

[69] Per S&P Global Ratings, "Portland General Electric," December 14, 2022, PGE has a BBB+ issuer rating.
[70] Value Line Investment Survey, Portland General Electric, October 3, 2022.

<u>The CAPM Based Cost of Equity Estimation</u>

Q. Please briefly explain the CAPM.

A. The Capital Asset Pricing Model (CAPM) assumes the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets[71] 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 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, S (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 market risk premium. Mathematically, the relationship is given by the following equation:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \qquad (1)$$

Where,

$\boldsymbol{r_S}$ is the cost of capital for 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 a "risk-positioning model," which operates on the principle (corroborated by empirical data) that investors price risky securities to offer a higher expected rate of return

[71] Risky assets are assets that exposes investors to return and value risk. Technically, it is assets that are not risk-free, where risk-free assets commonly are treasury notes and government bonds in, for example, the U.S.

than safe securities. It says that an investment, whose returns do not vary relative to market returns, should receive the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 2), whereas investments of the same risk as the overall market (i.e., those that by definition have average systematic market risk) are priced to expect to return the risk-free rate plus the MRP. Further, it says that the risk premium of a security over the risk-free rate equals the product of the beta of that security and the MRP.

<u>Inputs to the CAPM</u>

Q. What inputs does your implementation of the CAPM require?

A. As demonstrated by equation (1) above, estimating the cost of equity for a given company requires a measure of the risk-free rate of interest and the MRP, as well as a measure of the stock's beta. Several choices and sources of data inform the selection of these inputs. I discuss these issues below (additional technical details, along with a discussion of the finance theory underlying the CAPM are provided in Confidential Exhibit 1005).

Q. What values do you use for the risk-free rate of interest?

A. I use the yield on a 20-year U.S. Government Bond as the risk-free rate for purposes of my analysis. Recognizing the fact that the cost of capital set in this proceeding will begin in 2023 and extend through 2024, I rely on the forecasted yield on U.S. Government bond yields in 2023 and 2024. Specifically, BCEI predicts that the yield on a 10-year U.S. Government Bond yield will be 3.8% in 2023 and 3.3% in 2024.[72] I take the average of these two to get a forecasted 10-year U.S. Government Bond yield of 3.55 percent. I then adjust this forecasted yield upwards by 50 basis points, which is my estimate of the representative maturity premium

[72] Wolters Kluwer Blue Chip Economic Indicators, October 2022, p. 14 and December 2022, p. 3.

for the 20-year over the 10-year U.S. Government Bond.[73] This gives me a forecasted risk-free rate of 4.05 percent.[74]

Q. What value did you use for the MRP?

A. Like the cost of capital itself, the market equity 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 government bonds over some long historical period. Duff & Phelps (Kroll) performs such a calculation of the MRP using data from several sources.[75] The average market equity risk premium from 1926 to the present is 7.46% with slightly shorter or longer periods resulting in slightly higher or lower MRPs.[76] I use this historical value of the MRP as one input scenario to my CAPM analyses.

However, investors may require a higher or lower risk premium, reflecting the investment alternatives and aggregate level of risk aversion at any given time. As explained in Section D, there is evidence that investors' levels of risk aversion remain elevated relative to the recent past due to rising inflation, interest rates, geopolitical tensions, and commodity prices. In recognition of this evidence, I also perform the CAPM calculations using Bloomberg's forward-looking estimate of 4.50% for the market equity risk premium.[77] While the forward-looking estimate of the MRP from Bloomberg currently is below the historical average, the

[73] This maturity premium is estimated by comparing the average excess yield on 20-year versus 10-year U.S. Government Bonds over the period 1990 - 2022, using data from Bloomberg.
[74] The actual yield on 20-year U.S. Government Bonds as of December 30, 2022 was 3.87% according to Bloomberg.
[75] Duff & Phelps (Kroll) Cost of Capital Navigator, U.S. Cost of Capital Module, 2022.
[76] *Ibid.*
[77] Measured over a 20-year government bond (See Confidential Exhibit 1005, Schedule BV-17)

results from a DCF analysis on the firms in the S&P 500 index, as the FERC does, would result in a MRP of 7.2% to 8.8%.[78]

Q. Please summarize the parameters of the scenarios and variations you considered in your CAPM and ECAPM analyses.

A. The parameters are displayed in Figure 10 below. Scenario 1 and Scenario 2 both use the forecasted 20-year U.S. Government Bond yield for 2023 and 2024. This results in a risk-free rate of 4.05%. In Scenario 1, I pair this with the long-term average historic MRP of 7.46%, as estimated by Duff & Phelps (Kroll). In Scenario 2, I instead use Bloomberg's forecasted MRP of 4.50% as of November 30, 2022.

Figure 9
CAPM and ECAPM Scenarios

	Scenario 1	Scenario 2
Risk-Free Interest Rate	4.05%	4.05%
Market Risk Premium	7.46%	4.50%

Q. What Betas did you use for the companies in your sample?

A. I used Value Line betas, which are estimated using the most recent five years of weekly historical returns data.[79] The Value Line levered equity betas are reported in Figure 9 above. 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 higher proportion of debt financing than does the market data of the proxy companies used to estimate the ROE, the financial risk associated with an

[78] Based on FERC Methodology for MRP as of November 30, 2022, using IBES and Value Line data, respectively, and 20-year U.S. Government Bond yields (See Confidential Exhibit BV-3).
[79] See Value Line Glossary, accessible at: http://www.valueline.com/Glossary/Glossary.aspx.

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, the DCF model and the CAPM-based models use market data to estimate the ROE, so that it is the market value capital structure that is the relevant comparison across companies. 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.

Consequently, standard textbook techniques are applied to unlever the Value Line betas reported in Figure 9 above and relever the resulting asset betas at PGE's requested regulatory capital structure of 50 percent equity.[80]

<u>The Empirical CAPM</u>

Q. What other equity risk premium model do you use?

A. Empirical research has long 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.[81] Several 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 second version of the CAPM that I employ makes use of these empirical findings. It estimates the cost of capital with the equation,

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[80] The Technical Appendix (Exhibit BV-2) to this 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., Portland General's regulatory capital structure), with the precise relevered beta depending on the specific version of the unlevering/relevering formula employed.

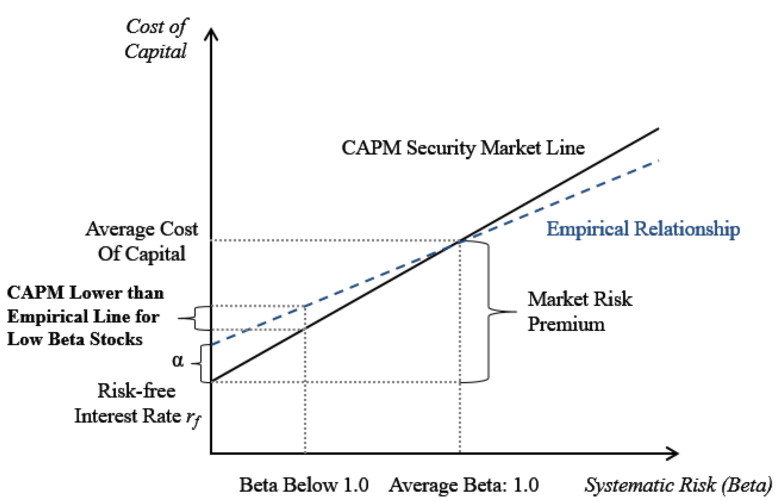
[81] The Technical Appendix (Exhibit BV-2) to this evidence for references to relevant academic articles.

$$\boldsymbol{r_S = r_f + \alpha + \beta_S} \times (\boldsymbol{MRP - \alpha}) \qquad (2)$$

where $\boldsymbol{\alpha}$ is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see equation (1) above).

I label this model the Empirical Capital Asset Pricing Model, or "ECAPM." The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line (see Figure 2), which results in a Security Market Line that more closely matches the results of empirical tests, as shown in Figure 11 below. In other words, the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

Figure 10
The Empirical Security Market Line



Q. Why do you use the ECAPM?

A. Academic research finds that the CAPM has not generally performed as well as an empirical model. One of its shortcomings is directly addressed by the ECAPM, which recognizes the consistent empirical observation that the CAPM underestimates the cost of capital for low beta stocks. In other words, the ECAPM is based on recognizing that the actual observed risk-return line is flatter and has a higher intercept than that predicted by the CAPM. The alpha parameter (α) in the ECAPM adjusts for this fact, which has been established by repeated empirical tests of the CAPM. In summary, these studies estimate alpha parameters that range between 1%[82] and 7.32%.[83] I apply an alpha parameter of 1.5% in my application of the ECAPM. Exhibit 1004 (Technical Appendix) provides further discussion of the empirical findings that have tested the CAPM and also provides documentation for the magnitude of the adjustment, α.

Results from the CAPM-Based Models

Q. Please summarize the results of the CAPM-based models.

A. The results of the CAPM and ECAPM estimation for the proxy groups is presented in Figure 12 below. The range of results for each model (CAPM and ECAPM) reflects the application of different specific versions of the textbook formulas used to account for the impact of differences in financial leverage on financial risk. In the figures below, I show estimates measured relative to PGE's requested 50% equity capital structure.

[82] Fischer Black. *Beta and Return*. THE JOURNAL OF PORTFOLIO MANAGEMENT vol. 20 (Fall): 8-18, 1993.
[83] Eugene F. Fama and Kenneth R. French. *The Cross-Section of Expected Stock Returns*. JOURNAL OF FINANCE, June, 1992, vol. 47, issue 2: 427-465.

Figure 11
Electric Utility Sample's CAPM Results at 50% Equity

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Electric Sample		
Hamada Adjustment Without Taxes		
CAPM	11.5%	8.5%
ECAPM (α = 1.5%)	11.5%	8.5%
Hamada Adjustment With Taxes		
CAPM	11.3%	8.4%
ECAPM (α = 1.5%)	11.3%	8.5%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 4.05%, Long-Term Market Risk Premium of 7.46%.
[2]: Long-Term Risk Free Rate of 4.05%, Long-Term Market Risk Premium of 4.50%.

Q. How do you interpret the results of your CAPM and ECAPM analyses?

A. The estimates measured relative to a 50% equity capital structure range from 8.4% to 11.5% for a midpoint of 10%.

DCF Based Estimates

Q. Please describe the DCF model's approach to estimating the cost of equity.

A. 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—a stream of expected "cash flows" discounted at a risk-appropriate discount rate. When the cash flows are dividends, that discount rate is the cost of equity capital:

$$\boldsymbol{P_0} = \frac{\boldsymbol{D_1}}{\boldsymbol{1+r}} + \frac{\boldsymbol{D_2}}{(\boldsymbol{1+r})^{\boldsymbol{2}}} + \frac{\boldsymbol{D_3}}{(\boldsymbol{1+r})^{\boldsymbol{3}}} + \cdots + \frac{\boldsymbol{D_T}}{(\boldsymbol{1+r})^{\boldsymbol{T}}} \qquad (3)$$

Where,

$\boldsymbol{P_0}$ is the current market price of the stock;

$\boldsymbol{D_T}$ is the dividend cash flow expected at the end of period $\boldsymbol{T}$;

$\boldsymbol{T}$ is the last period in which a dividend cash flow is to be received; and

$\boldsymbol{r}$ is the cost of equity capital.

Importantly, this formula implies that if the current market price and the pattern of expected dividends are known, it is possible to "solve for" the discount rate r that makes the equation true. Therefore, a DCF analysis can be used to estimate the cost of equity capital implied by the market price of a stock and market expectations for shareholders' future cash flow (e.g., dividends).

Many DCF applications assume that the growth rate lasts into perpetuity, so the formula can be rearranged algebraically to directly estimate the cost of capital. Specifically, the implied DCF cost of equity can then be calculated using the well-known "DCF formula" for the cost of capital:

$$\boldsymbol{r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1 + g) + g} \qquad (4)$$

where $\boldsymbol{D_0}$ is the current dividend, which investors expect to increase at rate $\boldsymbol{g}$ by the end of the next period, and over all subsequent periods into perpetuity.

Equation (4) says that if equation (3) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the simple (single-stage) DCF model; it is also known as the Gordon Growth model, in honor of its originator, Professor Myron J Gordon.

Q. Are there other versions of the DCF model?

A. Yes. There are many alternative versions, notably (i) multi-stage models, (ii) models that use cash flow rather than dividends, or versions that combine aspects of (i) and (ii).[84] One such

[84] 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. Confirmed in Surface Transportation Board Decision, "STB Docket No. EP 664 (Sub-No. 4)," decided June 23, 2020.

alternative expands the Gordon Growth model to three stages. In the multi-stage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period.[85]

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 GDP growth rate forecasted to be in effect ten years or more into the future).

DCF Inputs

Q. What growth rate information do you use?

A. The first step in my DCF analysis (either constant growth or multi-stage formulations) is to examine a sample of investment analysts' forecasted earnings growth rates for companies in my samples. For the single-stage DCF and the first stage of the multi-stage DCF, I use investment analyst forecasts of company-specific growth rates sourced from Value Line and Thomson Reuters/Refinitiv IBES.

For the long-term growth rate for the final, constant-growth stage of the multistage DCF estimates, I use the long-term U.S. GDP growth forecast of 3.9% from BCEI.[86] Thus, the long-run (or terminal) growth rate in the multi-stage model is nominal GDP growth.

Q. Please explain how input data can affect the DCF models.

A. The Gordon Growth/single-stage DCF models require forecast growth rates that reflect investor expectations about the pattern of dividend growth for the companies over a

[85] See Exhibit BV-2 (Technical Appendix) for further discussion of the various versions of the DCF model, as well as the details of the specific versions I implement in this proceeding.
[86] Wolters Kluwer Blue Chip Economic Indicators, October 10, 2022, p. 14. The October issue of the publication is the most recent version that has a long-term (2029 – 2033) GDP forecast.

sufficiently long horizon, but estimates are typically only available for three to five years. In addition, the DCF model assumes that the growth rates reflect stable economic conditions.

An issue with the data is that it solely includes dividend payments as cash distributions to shareholders, while some companies also use share repurchases to distribute cash to shareholders. To the extent that companies in my samples use share repurchases, the DCF model using dividend yields will underestimate the cost of equity for these companies. While there are companies in my sample that have engaged in share buybacks in the past, the magnitude is currently not large.

<u>Results From the DCF Based Models</u>

Q. Please summarize the DCF-based cost of equity estimates for the proxy groups.

A. The results of the DCF based estimation for the proxy groups are displayed below in Figure 13. Similar to my implementation of the CAPM/ECAPM, the estimates are measured relative to PGE's requested 50% equity capital structure.

Figure 12
Electric Sample's DCF Results at 50% Equity

	Simple	Multi-stage
	[1]	[2]
Electric Sample	10.5%	8.8%

Q. How do you interpret the results of your DCF analyses?

A. The estimates from the DCF model measure relative to a 50% equity capital structure range from 8.8% to 10.5% for a midpoint of 9.7%. I view the midpoint as downward biased due to the continued talks of a recession, so that the current growth rates may be below those expected after 2023. Lastly, I note that the constant growth DCF for the Electric Sample resulted in an average of 10.1% before financial risk considerations (see Confidential Exhibit 1005) and is thus supportive of the CAPM and overall results.

__Risk Premium Model Estimates__

Q. Did you estimate the cost of equity that results from an analysis of risk premiums implied by allowed ROEs in past utility rate cases?

A. Yes. In this type of analysis, sometimes called the "risk premium model," the cost of equity capital for utilities is estimated based on the historical relationship between allowed ROEs in utility rate cases and the risk-free rate of interest at the time the ROEs were granted. These estimates add a "risk premium" implied by the relationship to the relevant (prevailing or forecasted) risk-free interest rate:

$$Cost\ of\ Equity = r_f + Risk\ Premium \qquad (5)$$

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 allowed ROE at a given time and the then-prevailing interest rate to ensure that I am properly considering the interest rates at the time the ROE was awarded. This implementation ensures that I can compare the allowed ROE granted at different times and under different interest rate regimes.

Q. How did you use rate case data to estimate the risk premiums for your analysis?

A. The rate case data from Q1 1990 through Q3 2022 is taken from Regulatory Research Associates (RRA).[87] Using this data, I compared (statistically) the average allowed rate of

[87] S&P Capital IQ Pro, as of November 30, 2022.

return on equity granted by U.S. state regulatory agencies in electric rate cases to the average 20-year Treasury bond yield that prevailed in each quarter. I calculated the allowed utility "risk premium" in each quarter as the difference between allowed returns and the Treasury bond yield, since this represents the compensation for risk allowed by regulators. Then, I used the statistical technique of ordinary least squares ("OLS") regression to estimate the parameters of the linear equation:

$$Risk\ Premium = A_0 + A_1 \times (Treasury\ Bond\ Yield) \qquad (6)$$

I derived my estimates of A_0 and A_1 using standard statistical methods (OLS regression) and found that the regression has a high degree of explanatory power in a statistical sense. I report the results using a forecasted risk-free rate (consistent with the one used in my CAPM/ECAPM analysis) in Figure 14 below. I note that the results displayed below show that the risk premium model fits the data well as the R-squared is approximately 0.86 and R-squared is a measure of how well the data fits the model. An R-squared above 0.80 indicates a solid result.

Figure 13
Implied Risk Premium Model (Electric Utilities)

	R Squared	Estimate of Intercept (A0)	Estimate of Slope (A1)	Implied Cost of Equity Range
	[1]	[2]	[3]	[4]
Electric Utility	86.2%	8.6%	-56.5%	10.4%

Sources and Notes:
[1]-[3]: Estimated Using S&P Market Intelligence, as of November 2022
[4]: Risk-free rate of 4.05%

Q. What conclusions did you draw from your risk premium analysis?

A. The results in Figure 14 above indicate an ROE of 10.4% for an average electric utility based on the risk premium model, which is consistent with the range of the CAPM and DCF estimates. While the risk premium model is based on historically allowed returns and not underpinned by fundamental financial principles in the manner of the CAPM and DCF models, I believe that this analysis, when properly designed, executed, and placed in the proper context, is a valid and useful approach to estimate utility ROEs. Because the risk premium analysis, as implemented, considers the interest rates prevailing during the quarter the ROE decision was issued, it provides a useful benchmark for the cost of equity in any interest environment. Because it relies on the returns for regulated utilities, I believe this method provides a good way to directly assess whether the ROE is commensurate with that available to alternative regulated investments of similar risk.

<u>**Summary of Results**</u>

Q. Please summarize your results for an allowed ROE.

A. Figure 15 below displays the range of ROE results at PGE's requested 50% equity capital structure. Next, I consider PGE's and Oregon's specific risks to inform my recommendation of a reasonable ROE for PGE.

Figure 14
Summary of Ranges at 50% Equity

	Low End	High End	Midpoint
DCF	8.8%	10.5%	9.7%
CAPM	8.5%	11.5%	10.0%
Risk Premium	10.4%	10.4%	10.4%
Average			10.0%

Based on these results, the average of the midpoints is 10%; however, PGE is only seeking a still reasonable but lower 9.8% ROE. That is because a reasonable range for a generic electric utility falls within the midpoints of 9.7% to 10.4%. This range captures the central tendency of the results. All models yield results in this range.

D. PGE Specific Circumstances

Q. How does the business risk of PGE compare to that of the sample?

A. Like the Electric Sample companies, PGE's business is concentrated in the regulated electric industry. PGE has an investment grade credit rating of BBB+ from S&P Global Ratings, which is comparable to that of the sample.[88] PGE's business operations are concentrated in Oregon, which is viewed as an average regulatory environment by Regulatory Research Associates.[89] The Average/2 rating indicates a position near that of the median for the country.

However, there are several areas in which PGE faces higher risk than the peer group of electric utilities. Most notably, unlike many of its peers, PGE currently has a power cost adjustment mechanism (PCAM) with an asymmetric deadband whereby PGE must first absorb $30 million before sharing 90% of excess power costs with customers. It can only retain $15 million before refunding 90% of saved power costs to customers. According to Regulatory Research Associates, which is part of Standard & Poor's, the majority of electric utilities do not share power cost over or under recovery with customers and many have a decoupling mechanism.[90] Second, PGE has an ROE test of +/- 100 basis points, which makes it challenging to earn the allowed ROE if the company experiences higher than forecasted power costs because the company would only be allowed to share costs with customers 90% up to an ROE that is 100 basis points below its authorized ROE.

[88] S&P Global Ratings, "Portland General Company," December 14, 2022 and Figure 9.
[89] S&P Capital IQ, "Oregon Public Utility Commission," accessed January 10, 2023. Regulatory Research Associates Ranking reflects investors perspective of regulatory risk associated with owning securities in a given jurisdictions. There are three rating categories (Above Average, Average, Below Average) and the number designates a relative ranking within each category (stronger, mid-range, and weaker).
[90] S&P Global Intelligence, "RRA Regulatory Focus: Adjustment Clauses," July 18, 2022.

Q. Are there other areas where PGE faces higher risk than its peer group?

A. Yes. PGE is concentrated in one state, Oregon, whereas the majority of the comparable companies have operations in several states and therefore can diversify their risks across jurisdictions, geography, etc.

Additionally, PGE is smaller than the average electric utility and research has shown that the CAPM tends to underestimate the cost of equity for smaller companies. Specifically, Duff & Phelps calculates a size premium that they add to the cost of equity for companies that are smaller in size. The average electric utility in the sample has a market cap of approximately $10.2 billion, while that of PGE is about $3.8 billion, measured in October 2022.[91] Thus, the average electric sample company is included in Duff & Phelps' decile 4, while PGE is in decile 5. Duff & Phelps estimates that the size premium for a decile 5 company is approximately 1%.[92]

Lastly, the company has recently seen an increase in deferred costs, which according to Moody's exposes the Company to some risks.[93]

Q. Has the increased risk profile related to these circumstances affected the way investors and financial analysts valuate PGE?

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

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[91] Value Line Investment Survey, "Portland General," October 21, 2022.
[92] Duff & Phelps Cost of Capital Navigator as of December 31, 2022 (accessed 1/11/2023).
[93] Moody's Investor Service, "Portland General Electric Company," March 30, 2022.

[redacted] **[END CONFIDENTIAL]**

Q. Are there any other sources of increased risk profile that cause financial analysts to apply a discount to PGE's valuation?

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

Q. Can you please summarize your assessment of PGE's business risk relative to the sample?

A. Compared to the sample, PGE is in the same line of business and has a comparable credit rating. PGE does not currently have a revenue decoupling mechanism and, unlike the majority of the sample companies, has an asymmetric sharing mechanism for power costs. Lastly, PGE is smaller than the average sample company.

Consequently, PGE is riskier than the average or median risk profile of the sample companies given the volatility introduced by its PCAM, which is not a mechanism commonly experienced by its peers, which is consistent with the investor reports cited above.

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[94] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[95] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

E. Summary of Recommendations

Q. What do you recommend for PGE's cost of equity in this proceeding?

A. The DCF for the sample shows an average of 9.7% and the CAPM-based results average 10.0%. The risk premium model shows higher results. Thus, it is reasonable to place PGE in the range of 9.7% to 10.4%, which was determined as the range of the three models. PGE's request of 9.8% is reasonable and conservative relative to the range of outcomes. I note that this recommendation does not consider any size premium – nor does it add to the ROE due to PGE specific risks.

V. Capital Structure

Q. How did you determine the appropriate regulatory capital structure for 2022?

A. We evaluated PGE's regulatory capital structure using the forecasted income statement and balance sheet for 2024. Additionally, we considered several factors, including: 1) PGE's need to maintain its financial strength; 2) flexibility and adequate liquidity; 3) its ability to maintain reliable and economical access to the capital markets; 4) minimizing the cost of capital to customers and shareholders; and 5) Commission Order No. 22-129 in Docket No. UE 394 (UE 394). We also considered PGE's desire to maintain a capital structure consisting of 50% long-term debt and 50% equity.

Q. Has the Commission recently approved a 50% equity and 50% debt regulatory capital structure for other utilities in Oregon?

A. Yes. In Docket No. UE 399, the Commission adopted a settlement among the parties that re-approved an equity percentage of 50% for PacifiCorp in line with Staff's recommendation.

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 will be drawn on throughout 2023.

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 394?

A. No. In UE 394, 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 capital structure at 50% equity and 50% debt. The equity ratio continues to fluctuate above and below the 50% target level over time, due to the phasing and sizing of debt and equity issuances.

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 that the 50% equity in PGE's capital structure helps it 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. Additionally, PGE faces risks in today's banking environment because of its relatively small size, and it must maintain a solid capital structure and financial flexibility to help 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:

- Hydro and wind availability and weather changes, including wildfires, create risk for PGE in several ways, including: lower than average stream flows; lower than average wind speeds and when the wind generates; and volatility in electricity usage because of sudden, unexpected weather changes and severe storms and wildfires. These risks can potentially force PGE to purchase more spot energy when the markets may be tight. The costs resulting from these purchases could be greater than what is included in customer prices.

- Regional economic weakness can adversely affect PGE's revenues. Weakness in Oregon's economy can lead to a decline in electricity usage as customers become more conservative. This can negatively impact PGE's revenues, thereby reducing 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.[96] PGE could be vulnerable to 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.
- Uncertain federal and state energy policy from legislative or regulatory efforts to reduce greenhouse gas emissions and water discharges from thermal plants could lead to increased capital and operating costs. Operating changes required of PGE in order to comply with existing and new laws related to fish and wildlife also 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.

[96] https://investors.portlandgeneral.com/sec-filings/sec-filing/10-k/0000784977-21-000007 Starting with page 115, Note 19- 2020 SEC Form 10-K. https://investors.portlandgeneral.com/sec-filings/sec-filing/10-q/0000784977-21-000023. Starting with page 24, Note 8- the most recent 4/30/21 PGE SEC Form 10-Q.

Q. Can PGE mitigate these risks?

A. PGE can manage some of these risks, but not others. 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 it for the 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 formal recovery plans to address disasters and implement emergency management procedures.

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 7.059% cost of capital for the 2024 test year. This cost of capital reflects PGE's updated request for return on equity (ROE) of 9.80%, its currently authorized capital structure of 50% debt and 50% equity, and an updated long-term cost of debt of 4.317%.

VI. 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, Financial Planning & Analysis, Forecasting, Regulatory Affairs, and Utility Asset Management. In my current role I am responsible for Accounting, Reporting, SOX, 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. Dr. Villadsen, please state your educational background and experience.

A. I have 23 years of experience working with regulated utilities on cost of capital and related matters. My practice focuses on cost of capital, regulatory finance, and accounting issues. I am the co-author of the text, "Risk and Return for Regulated Industries," and a frequent speaker on regulated finance at conferences and webinars. I have testified or filed expert reports on cost of capital before regulators in Alaska, Arizona, California, Hawaii, Illinois, Iowa, Michigan, New Mexico, New York, Ohio, Oregon, Virginia, and Washington, as well as before the Bonneville Power Administration, the Federal Energy Regulatory Commission (FERC), and the Surface Transportation Board (STB). I have provided testimony to the Alberta Utilities Commission, the Ontario Energy Board, Quebec's Régie de l'énergie and provided white papers on cost of capital for the British Columbia Utilities Commission and the Canadian Transportation Agency. I have also provided white papers or expert reports on cost of capital before Mexico's Comisión Reguladora de Energía, the Barbados Fair Trading

Commission as well as in Australia and Europe. I have testified or filed testimony on regulatory accounting issues before FERC, the Regulatory Commission of Alaska, the Michigan Public Service Commission, the Texas Public Utility Commission, as well as in international and U.S. arbitrations, and have regularly provided advice to utilities on regulatory matters and risk management.

I hold a Ph.D. from Yale University and a BS/MS from the University of Aarhus, Denmark. Exhibit 1003 contains more information on my professional qualifications as well as a list of my prior testimonies and publications.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1001C	Cost of Long-Term Debt
1002	Standard & Poor’s and Moody’s Investors Service Credit Ratings
1003	Resume of Bente Villadsen
1004	Technical Appendix
1005C	Workpapers of Bente Villadsen

Exhibit 1001 contains confidential information and is subject to

Modified General Protective Order 23-039.

Information provided in electronic format only.

Standard & Poor's and Moody's Investors Service Credit Ratings

	S&P	Rating Date	Moody's	Rating Date
Senior Secured Debt	A	1/14/2022	A1	3/30/2022
Senior Unsecured	BBB+	1/14/2022	A3	3/30/2022
Short-term/ Commercial Paper	A-2	1/14/2022	P-2	3/30/2022

"Credit Opinion: Portland General Electric Company" January 14, 2022. Standard & Poor's
"Credit Opinion: Portland General Electric Company" March 30, 2022. Moody's Investors Service

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is assisting entities in the acquisition of regulated utilities regarding issues such the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Dr. Villadsen's accounting work has pertained to disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions on accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, Dr. Villadsen was a faculty member at Washington University in St. Louis, University of Michigan, and University of Iowa.

She has taught financial and managerial accounting as well as econometrics, quantitative methods, and economics of information to undergraduate or graduate students. Dr. Villadsen served as the president of the Society of Utility Regulatory Financial Analysts for 2016-2018.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit worthiness
  - Risk Management
  - Regulatory Advisory in Mergers & Acquisitions
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Forensics
  - Credit Issues in the Utility Industry
- Damages and Valuation (incl. international arbitration)
  - Utility valuation

- Lost Profit for construction, oil&gas, utilities
- Valuation of construction contract
- Damages from the choice of inaccurate accounting methdology

EXPERIENCE

Regulatory Finance

- Dr. Villadsen has testified on cost of capital and capital structure for many regulated entities including electric and gas utilities, pipelines, railroads, water utilities and barges in many jurisdictions including at the FERC, the Surface Transportation Board, the states of Alaska, Arizona, California, Hawaii, Illinois, Iowa, Michigan, New Mexico, New York, Oregon, Virginia and Washington as well as in the provinces of Alberta, Ontario, and Quebec.
- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board (STB) and submitted expert reports on the determination of the cost of equity for U.S. freight railroads. The STB agreed to continue to use two estimation methods with the parameters suggested.
- On behalf of two taxpayers, Dr. Villadsen has testified on the methodology used to estimate the discount rate for the income approach to property valuation in Utah district court.
- For several electric, gas and transmission utilities as well as pipelines in Alberta, Canada, Dr. Villadsen filed evidence and appeared as an expert on the cost of equity and appropriate capital structure for 2015-17. Her evidence was heard by the Alberta Utilities Commission.
- On behalf of gas distribution and storage utilities in Quebec, Dr. Villadsen provided expert testimony on the appropriate cost of equity and capital structure for of Énergir, Gazifère, and Intragaz before Régie de l'énergie du Québec.
- For Barbados Light & Power, she provided testimony on the appropriate weighted average cost of capital including the cost of equity, the cost of debt, and capital structure. The matter was heard by the Barbados Fair Trading Commission.
- For potential acquirers of electric, natural gas, and water utilities, Dr. Villadsen has conducted regulatory due diligence in the form of an assessment of the regulatory environment in the jurisdictions at issue including the ability to earn the allowed return and recover costs associated with operations or capital expenditures. Her evaluations also involved an assessment of needed capital expenditures and the recovery of such expenditure through rates or specific

adjustment clauses. Her prior work includes more than 15 US states, the FERC, and several Canadian provinces.

- She has worked on formula rates for transmission companies at FERC; including matters where specific issues such as the determination of the rate base, the treatment of leases, and the recovery of transaction costs have been litigated.
- Dr. Villadsen has estimated the cost of capital and recommended an appropriate capital structure for natural gas and liquids pipelines in Canada, Mexico, and the US. using the jurisdictions' preferred estimation technique as well as other standard techniques. This work has been used in negotiations with shippers as well as before regulators.
- For the Ontario Energy Board Staff, Dr. Villadsen submitted evidence on the appropriate capital structure for a power generator that is engaged in a nuclear refurbishment program.
- Dr. Villadsen has advised many acquirers and potential acquirers of regulated utilities regarding the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Her work has pertained to many jurisdiction in the U.S. and Canada including more than 20 states and three provinces as well as the Federal Energy Regulatory Commission. She has worked on electric, natural gas, pipeline, transmission, and water utility acquisitions.
- She has estimated the cost of equity on behalf of entities such as Anchorage Municipal Light and Power, Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, NW Natural, Nicor, Consolidated Edison, Southern California Edison, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the FERC on behalf of electric transmission and natural gas pipelines as well as Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also capital structure, the impact on credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.
- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted

a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.

- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.
- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.
- She has worked on behalf of infrastructure funds, pension funds, utilities and others on understanding and evaluating the regulatory environment in which electric, natural gas, or water utilities operate for the purpose of enhancing investors ability to understand potential investments. She has also provided advise and testimony in the approval phase of acquisitions.
- On behalf of utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- For a FERC-regulated entity, Dr. Villadsen undertook an assessment of the company's classification of specific long-term commitments, leases, regulatory assets, asset retirement obligations, and contributions / distributions to owners in the company's FERC Form 1.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated electric utilities,

transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.

- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.
- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties. For the owner of Heathrow and Gatwick Airport facilities, she has assisted in estimating the cost of capital of U.K. based airports. The resulting report was filed with the U.K. Competition Commission.

- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration between the pipeline owner and its shippers.
- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance. Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.
- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.

- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).
- For several infrastructure companies, Dr. Villadsen has provided advice regarding the regulatory issues such as the allowed return on equity, capital structure, the determination of rate base and revenue requirement, the recovery of pension, capital expenditure, fuel, and other costs as well as the ability to earn the allowed return on equity. Her work has spanned 14 U.S. states as well as Canada, Europe, and South America. She has been involved in the electric, natural gas, water, and toll road industry.
- For an electric utility, Dr. Villadsen provided guidance regarding the regulatory accounts needed as the utility was separated into separate generation, transmission, and distribution entities with each their accounting records.

Accounting and Corporate Finance

- For an electric utility subject to international arbitration, Dr. Villadsen submitted expert testimony on the application of IFRS as it pertains to receivables, the classification of liabilities and contingencies.
- In international arbitration, she submitted an expert report on IFRS' requirements regarding carve out financials, impairment, the allocation of costs to segments, and disclosure issues.
- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert report report quantifying damages in the form of lost profit and consequential damages.
- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.
- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- On behalf of a taxpayer, Dr. Villaden has provided an expert report on the nature of the cost of equity used in regulatory proceedings as well as the interest rate regine in 2014.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs

and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.

- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.
- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.
- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.

- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.
- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.

- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.

- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.

- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.

- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.

- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.

- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.

- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.

- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

BOOKS

"*Risk and Return for Regulated Industries*," (with Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe) Elsevier, May 2017.

PUBLICATIONS AND REPORTS

"International Rate of Return Methods – Recent Developments," (with Toby Brown and Andrew W. Thompson), prepared for Energy Networks Australia and submitted to the *Australian Energy Regulator*, September 2022.

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Technical Support for the Direct Testimony of Bente Villadsen

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 Electric's requested regulatory capital structure.

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I. 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:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \tag{1}$$

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 (1), 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 (1) 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

$$P_0 = \frac{D_1}{r-g} \tag{2}$$

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 (2) is a simplified version of Equation (1) that can be solved algebraically to yield the well-known "DCF formula" for the cost of equity capital,

$$r = \frac{D_1}{P_0} + g = \frac{D_0 \times (1+g)}{P_0} + g \tag{3}$$

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 (1)).

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 (1)).[1]

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 (1)). Focusing on *available* cash rather than that actually distributed in the form of dividends can help account for instances when near-term investing and 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.

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1 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. The methodology was confirmed in EP-664 (Sub-No. 2), October 31, 2016 and EP 664 (Sub-No. 4), June 23, 2020.

Many utility companies such as those included in my proxy group have long histories of paying a dividend. In fact, as mentioned in Section I of this Appendix, one of my standard requirements for inclusion in my proxy group is that a company pays dividends for 3-years without a gap or a dividend cut (on per share basis).

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 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."[2] Thus, some recent research indicates that the analyst bias may be a problem of the past.

[2] A. Hovakimian and E. Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts Journal*, vol. 66, 2010.

The findings of several academic studies[3] 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, firms with weaker audits or firms whose prospects are uncertain. 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*.[4]

II. 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 3 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:

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3 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; (iii) Michel, J-S., Pandes J.A. (2012), "Are Analysts Really Too Optimistic?" downloaded from http://www.efmaefm.org; and Wen He, Baljit Sidhu and Stephen Taylor, "Audit Quality and Properties of Analysts' Information Environment," *Journal of Business, Finance & Accounting*, vol 46, 2018.

4 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.

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \tag{4}$$

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 weight 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,

$$\boldsymbol{\beta_s} = \frac{covariance(\boldsymbol{r_s}, \boldsymbol{R_m})}{variance(\boldsymbol{R_m})} \tag{5}$$

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 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.[5]

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.[6] 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 as currently prevailing bond yields are near historic lows for a variety of circumstances that should not be expected to persist for the reasons discussed in my direct testimony.

As shown in Figure B-1 below, the spread between utility bond yields and the 20-year Treasury bond yield was elevated by about 68 basis points at the time of my November 30, 2022 analysis. While elevated, I conservatively do not rely on this to adjust the risk-free rate or MRP.

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5 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

6 The use of a 20-year government bond is consistent with the measurement of the 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).

Figure B-1: Yield Spreads – November 30, 2022

Periods	A-Rated Utility and Treasury	BBB-Rated Utility and Treasury	Notes
Period 1 - Average Mar-2002 - 2007	1.05	1.43	[1]
Period 2 - Average Aug-2008 - Nov-2022	1.46	1.89	[2]
Period 4 - Average 15-Day (Nov 08, 2022 to Nov 30, 2022)	1.47	1.74	[3]
Spread Increase between Period 2 and Period 1	0.41	0.46	[4] = [2] - [1]
Spread Increase between Period 4 and Period 1	0.42	0.32	[5] = [3] - [1]

Sources and Notes:
Spreads for the periods are calculated from Bloomberg's yield data.
Average monthly yields for the indices were retrieved from Bloomberg as of November 30, 2022.

I rely on Blue Chip's average forecast of 3.55% for the yield on a 10-year Treasury bond for 2023-2024[7] and 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.

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 use 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 7.46% for annual observed premiums of 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 7.46%.[8]

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

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[7] Blue Chip Economic Indicators, October and December 2022.

[8] Knoll, Cost of Capital Navigator as of November 2022.

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 5.54 percent. I note that the forward-looking MRP recently calculated using FERC's methodology in Order 569 and 569-A yields a higher MRP.

3. Beta

I rely on betas from Value Line, which uses five years of weekly data to calculate its beta.

C. The Empirical CAPM

1. Description of the ECAPM

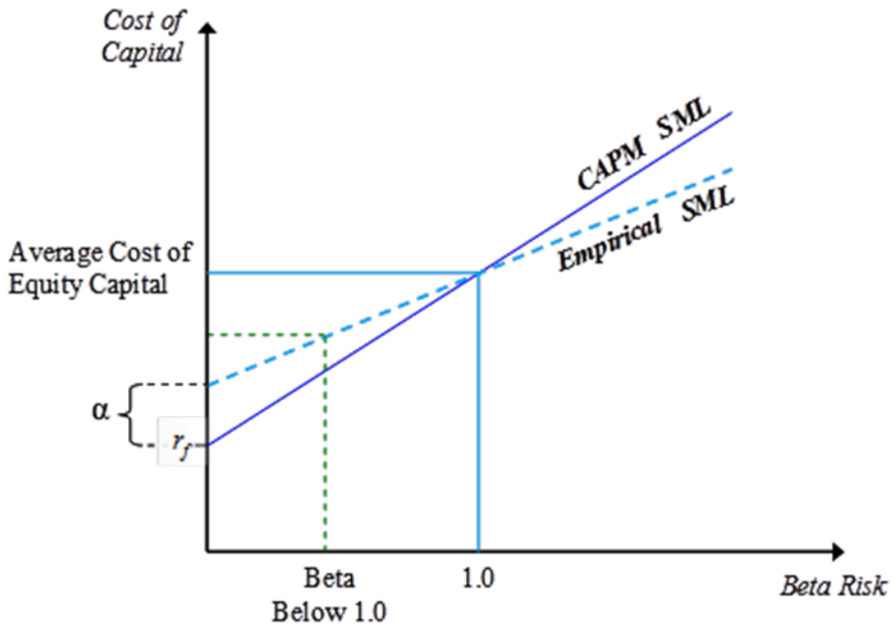
Empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. A number of variations on the original 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,

$$\boldsymbol{r_S = r_f + \alpha + \beta_S \times (MRP - \alpha)} \quad (6)$$

where $\boldsymbol{\alpha}$ is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see Equation (4)). 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.

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 company.[9] 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.[10]

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).

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[9] This is also a common valuation problem in general business contexts.

[10] 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

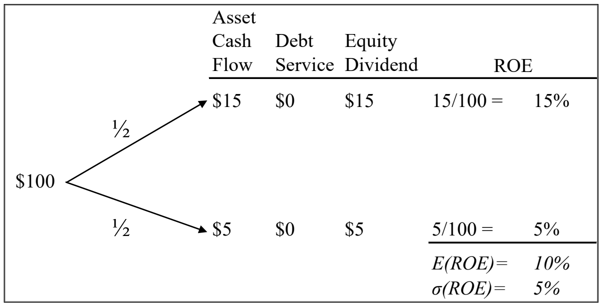
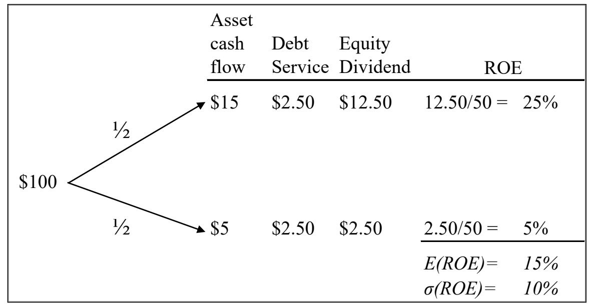


Figure B-5: 50/50 Capital Structure



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.[11] The expected return to the underlying asset is therefore equal to the value weighted

[11] 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 my analysis, I attribute the same implied yield to the cost of preferred equity as to the cost of debt.

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.[12]

$$\boldsymbol{r}^* = \frac{E}{V} \times r_E + \frac{D}{V} \times r_D(1 - \tau_c) \tag{7}$$

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.[13]

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.[14] 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 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

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12 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.

13 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.

14 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.

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,[15] 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,[16] the latter can still be shown to be constant across a broad range of capital structures.[17]

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.[18]

2. Unlevering and Relevering Betas in the CAPM (Hamada Adjustment)

The most common approach to account for the impact of financial risk on the CAPM results is to examine the impact of leverage on beta.

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15 Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

16 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.

17 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.

18 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:[19]

$$V = V_U + PV(ITS) \tag{8}$$

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
$PV(ITS)$ 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:

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \tag{10}$$

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

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[19] 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).

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:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \tag{11}$$

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 principal, 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.[20]

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 for the regulated target company, this estimate of unlevered beta can be "re-levered" to the regulated

[20] Berk, J. & DeMarzo, P., *Corporate Finance, 2nd Edition.* 2011 Prentice Hall, p. 389.

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 who contributed to their development[21]—are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

21 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 1005 contains confidential information and is subject to Modified General Protective Order 23-039.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Amber Riter
Shannon Greene

February 15, 2023

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I. Introduction

Q. Please state your names and positions with Portland General Electric Company (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 this testimony.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to present PGE's 2024 test year energy and customer forecast.

Q. How is your testimony organized?

A. This testimony provides an overview of PGE's load forecast methodology, provides details on several significant methodological changes, and presents the load forecast, first describing inputs and then the 2024 test year forecast result.

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 2024.

Q. Does PGE intend to update its 2024 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 as done in 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. At what cadence does PGE intend to update its 2024 forecast during this case?

A. The need for a load forecast update at PGE is assessed internally on a quarterly basis for a forecast release in March, June, September, and December. The forecast presented in this testimony reflects PGE's December 2022 load forecast. PGE intends to update the load forecast for this proceeding in June of 2023, and again in September of 2023. The June forecast update will be presented in PGE's reply testimony.

Q. Please describe PGE's delivery forecast.

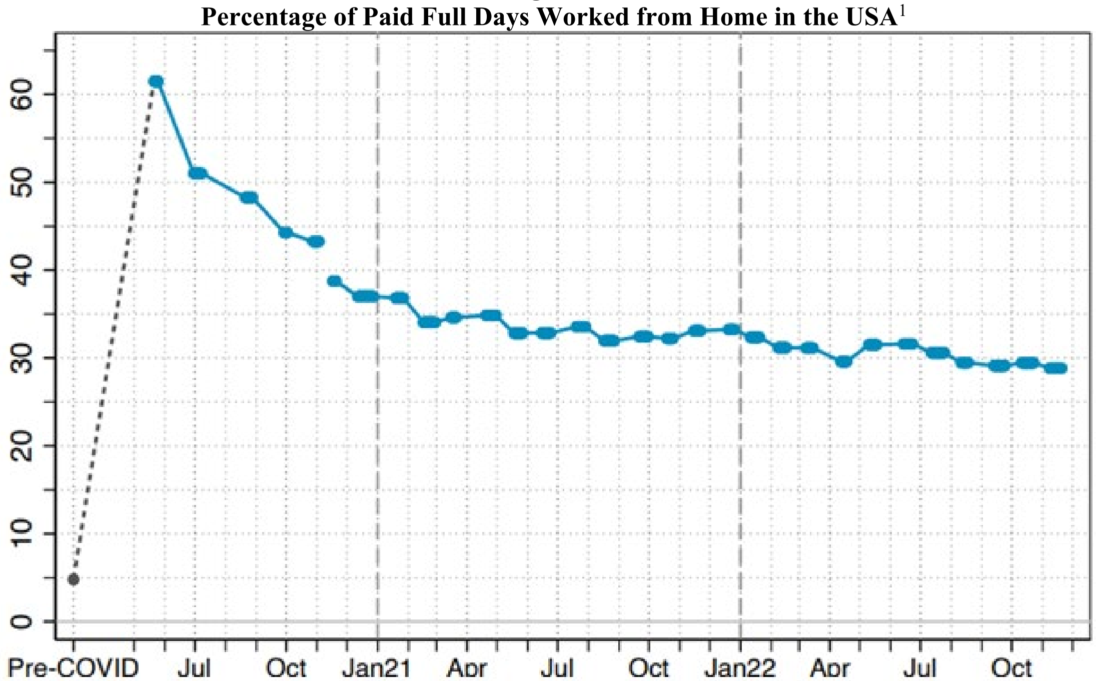
A. PGE's 2024 test year energy forecast is for energy deliveries of 22,083 gigawatt hours (GWh), on a cycle-month (billing) basis, including deliveries to customers who opted out of PGE cost-of-service rates for direct access under Schedules 485, 489 and 689. The forecast reflects current expected economic conditions for Oregon in 2024, 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. What impact has COVID-19 had on PGE's energy deliveries?

A. The COVID-19 pandemic significantly altered the way PGE's customers use electricity. Residential customers increased electric consumption as the nation entered lockdown, for the

12 months ending March 2021, and weather-adjusted energy deliveries increased by 6.3%. As restrictions were lifted and some workers returned to work, usage began to decrease. However, as some amounts of work from home continued, residential usage remained above pre-pandemic levels. As of late 2022, we believe residential average use-per-customer has largely stabilized. This behavioral change has been corroborated by national research that has found that work from home has stabilized over the last two years, with about 30% of full-time work happening at home.[1] Due to this, we now expect that the impacts (that is, increased residential load) of COVID-19 are fully embedded in usage and that residential customers will not fully return to pre-pandemic levels in the near term.

Figure 1
Percentage of Paid Full Days Worked from Home in the USA[1]



The COVID-19 pandemic did not impact all non-residential sectors evenly. For small and medium-sized commercial customers, or non-residential customers on secondary voltage

[1] Barrero, Jose Maria, Nicholas Bloom, and Steven J. Davis, 2021.
"Why working from home will stick," National Bureau of Economic Research Working Paper 28731, available at: https://wfhresearch.com/wp-content/uploads/2022/12/WFHResearch_updates_December2022.pdf .

service – referred to in this testimony as "commercial," usage dropped starkly in the first year of the pandemic reflecting stay home orders and business closures during that time frame. Commercial sector weather-adjusted deliveries for the 12 months ending March 2021 were 7.3% below the same period ending in March 2020. The commercial sector began to see recovery in 2021 as employment and consumer spending began to recover. As we approach three years since the onset of the pandemic, total commercial customer energy deliveries have returned to pre-pandemic levels.

The large commercial and industrial customer class, or non-residential customers on primary or sub-transmission voltage – referred to in this testimony as "industrial," saw little change in the trajectory of energy deliveries growth due to the pandemic. While customers reported closures for periods of time due to workplace outbreaks, and supply constraint impacts on business activities, expansion in the class continued with minor disruptions.

Q. How does the 2024 forecast compare to recent historical demand?

A. The 2024 forecast reflects strong growth in deliveries to industrial customers related to high-tech expansion and new data centers. The rate of growth in deliveries to industrial customers has increased in recent years following ongoing large high-tech expansion projects.

While residential average usage has increased dramatically from pre-pandemic levels due to COVID-19-related behavioral response, the trajectory for the near-term residential use-per-customer is a decrease. Residential average use-per-customer is expected to decrease due to energy efficiency and rooftop solar, partially offset by electrification and customer growth.

In recent history, commercial energy deliveries growth has been largely offset by energy efficiency. Forecasted decreases in commercial energy usage due to energy efficiency are expected to be partially to mostly offset by building and transportation electrification. Commercial energy deliveries are also expected to be depressed in the near term due to a recession which is forecasted in the base case economic forecast.

Table 1, below, summarizes the GWh delivery forecast in annual percentage changes on a weather-adjusted, billing cycle basis from 2020 through 2024.

Table 1
Change in MWh Delivery from Preceding Year: 2020-2024

Voltage Service Class	2019	2020	2021	2022	2023 (E)	2024 (E)
Residential	-2.0%	4.9%	1.4%	-0.9%	0.5%	0.7%
Commercial	-1.5%	-6.8%	3.5%	0.2%	0.3%	-0.8%
Industrial	6.6%	6.5%	8.3%	10.3%	9.8%	10.6%
Total	0.1%	0.8%	3.8%	2.4%	3.0%	3.2%

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 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[2]	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%	N/A	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%	N/A	-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%	N/A	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%	N/A	0.8%

2 Results for 2022 Benchmark Survey are not yet released

II. Forecast Methodology and Input Assumptions

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, 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. 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. What sources of information do you use to forecast energy deliveries?

A. PGE uses several third-party forecasts as inputs to the models. 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 distributed energy resources are provided by PGE's Distribution System Planning (DSP) team.

For historical data, PGE models are based on 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 official Oregon series maintained by the Oregon Employment Department.

[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.

Quarterly savings reports from ETO are used to develop a historical time series of energy efficiency savings.

Finally, customers who are large energy users often provide operational information, direct inputs, and, if available, forecasts of energy use through correspondence with PGE's Key Customer Managers.

Q. How current are the inputs used for the 2024 test year forecast?

A. The models estimated for use in this proceeding are based on historical data through the October 2022 billing cycle and new connects data through June 2022.[4] OEA's December 2022 economic forecast was used to reflect economic conditions and the ETO provided an updated near-term forecast in November 2022.

Q. Are these models different from previous PGE energy delivery models?

A. Yes. PGE has made methodology changes since our last general rate case, Docket No. UE 394. The last several years have marked unprecedented, rapid changes in how customers use electricity, which the prior models were largely unable to capture. This dramatic shift marked an opportunity to assess changes to PGE's model that better aligns the overarching model structure with the most recent data, trends, and usage drivers. In summary, the following items were addressed:

1) The customer groupings used for regression analysis were revisited. The groupings used for analysis have been updated and the number of total models has been reduced.

[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.

2) The approach used to account for energy efficiency was reassessed. Energy efficiency is now included as an explanatory variable, negating the need for PGE's prior out-of-model incremental energy efficiency adjustment.
3) The impact of incremental passive Distributed Energy Resources (DERs) on the energy deliveries forecast has been explicitly accounted for.

These changes are described in detail in Section 3.

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. The historical energy usage of these customers is removed from the data used to estimate the regression models.

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; and

4) these monthly gross load volumes are fit to a historically-based 8760 profile to create an hourly output file.

III. Methodological Updates

A. Regression Models

Q. Please describe the residential forecast models for the 2024 test year.

A. For residential customers, we model both customer counts and usage per customer. When modeling residential customer segments, we consider 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. Has this changed since UE 394?

A. Yes. PGE's prior residential models were grouped by both dwelling type and heat type (electric and non-electric) for seven total models. While the heat type groupings have been informative in the past, PGE found that consolidation of the heat type led to better model performance.

The heat type indicator variable is most often tracked during move in/move out process and is often out of date. As the model estimation period has been truncated to reflect more recent data, twelve years, a time frame in which less direct fuel switching has occurred, the distinction between heat types in the model has been less useful. In the last year, the residential models showed deterioration in performance, this was alleviated with the consolidation of the heat type specification in model grouping.

Q. Have any changes been made to model specifications to account for COVID-19 for residential models since UE 394?

A. Yes. In UE 394, PGE's residential use-per-customer models included indicator variables reflecting phased recovery from COVID-19. This indicator variable was forecasted into the future to reflect anticipated recovery, assuming that the long-term impact would be one-third of the estimated impact in the initial phase.

As time has passed, and with more historical usage data since the early phases of COVID-19 related closures, we no longer include a COVID-19 specific indicator variable. Instead, COVID-19 is controlled for using several step variables as well as an interaction between step variables and weather variables. Specifically, the early impacts of COVID-19 are captured by indicating the first six months of the pandemic when lockdowns were at their peak. In addition, an indicator variable, which begins in April of 2020 and continues into perpetuity, is interacted with weather variables, as increased time spent at home has changed residential customers' need for heating and cooling in response to weather conditions.

Q. Please describe the non-residential forecast models for the 2024 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 Schedule 89.

Q. Have the non-residential customer groupings changed since UE 394?

A. Yes. PGE's prior commercial and manufacturing models were based on industry segment type using eleven NAICS (North American Industry Classification System) code-based segments. In recent years, the data classifications have become less reliable, leading to increased need for control mechanisms used to reflect single or multiple month volatility in the data. The issue was perpetuated by having many model groups because the impact of data anomalies on very small customer groups could be quite large. Further, the loss of statistical significance of economic drivers, an important theoretical driver of non-residential deliveries, continued to be an issue. In UE 394, only two sector models included an economic driver. This meant that

PGE's models required use of an indicator variable to control for the impacts of COVID-19 since the economic conditions were not captured in most models. The degrading model performance caused PGE to reassess the model groups and switch to a rate-schedule based model grouping.

Rate schedules are assigned based on the customer usage level, which is a natural fit for group customers for statistical analysis. By aggregating the data into five model groups (instead of the previous eleven groups) the noise in the data was significantly reduced. Model testing found economic drivers were significant in four of the five models, and that the variability in those economic drivers, primarily employment, appropriately captured the impacts of COVID-19 on non-residential deliveries. This allows for continued recovery to be linked to economic conditions via the Oregon employment forecast rather than a subjective input assumption developed by PGE.

Rate schedule models also improve alignment with internal forecast user needs. Since the pricing model relies on forecasted usage by rate schedule, a forecast developed in this manner allows for more direct estimation, with less reliance on historical ratios and data transformation to create the needed output for billing determinants.

Finally, a higher level of aggregation allowed testing of a new approach to account for energy efficiency which is described below.

Q. How were the models tested?

A. PGE's model testing procedure remained consistent with that described in prior dockets. All models were reviewed to confirm that significant variables had logical signs and magnitude of coefficients. When initial testing of the new forecast model grouping was performed, backcasting of each model was implemented to confirm that the models were performing well. For each forecast group, PGE reviews a variety of alternate model specifications. Model residuals were reviewed, confirming that they appeared uncorrelated and normally distributed. PGE also reviewed regression output statistics, such as the Durbin Watson (DW) statistic, adjusted r squared (R^2), and Akaike Information Criterion (AIC). PGE inspected the time series plots to assess model performance and to look for outliers. An evaluation of the autocorrelation for each series was performed and an autoregressive (AR) term was added when applicable.

B. Energy Efficiency and Distributed Energy Resources

Q. What challenges do rapidly evolving programs and end uses pose to regression-based, econometric forecasts?

A. Regression analyses focus on estimating quantitative relationships between variables. Econometric forecasts cannot account for nascent changes in end uses that impact energy deliveries as there is no historical data available to use in modeling. This issue has been presented in energy deliveries forecasting literature when discussing accounting for energy efficiency and changes in codes and standards. In the future, capturing the rapid evolution of transportation electrification, building electrification and rooftop solar will cause similar challenges.

Q. What are common approaches in the utility industry literature to account for energy efficiency (EE) in the load forecast?

A. There are three common approaches[5] used for electric utilities to account for the load impacts of EE on energy deliveries forecasts:

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[5] Stuart McMenamin & Mark Quan, Incorporating DSM into the Load Forecast. Itron Energy Forecasting & Load Research, Publication 101027WP-01, 03/2010, available at: https://www.itron.com/-/media/feature/products/documents/white-paper/incorporating-dsm-into-the-load-forecast.pdf

1) Trend or Out-of-model adjustment: This approach does not account for EE in the regression model itself, but subtracts future, incremental, changes from the forecast. This approach is commonly used when there is expected to be significant acceleration of program activity.
2) Add-Back Method: This approach adjusts the historical series to account for the impact of EE prior to model estimation, essentially to estimate the model as if the savings had never occurred. This approach is often used when detailed, high quality historical data is available.
3) Independent variable method: This approach accounts for savings by including a representative driver as an explanatory variable in the regression analysis. This approach might be used when some historical data is available, but it is not detailed or precise enough to employ the add back method.

There are benefits and issues associated with each approach. In this section we will describe our approach for accounting for energy efficiency, electrification, and rooftop solar in the forecast, including the broad method chosen and reasons for the selection.

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, or the independent variable method (Method 3).

Q. Has PGE made any changes to the way energy efficiency is handled in its forecasting model since UE 394?

A. Yes. PGE changed the approach to the energy efficiency adjustment. Previously, PGE performed an out-of-model adjustment to account for the incremental impact of energy efficiency associated with EE programs funded through Schedule 109 Incremental EE Funding, enabled by Senate Bill 838 (Method 1).

Q. Why did PGE make this change?

A. While an out-of-model adjustment is a standard approach to account for DSM, over the last several rate cases, stakeholders (including Commission Staff and CUB) have shared concerns of double counting by using this method.[6] Given use of trend variables in its prior residential models, and the long-standing nature of energy efficiency programs in Oregon, PGE opted to test alternative methods to alleviate any concern of double counting.

Development of the rate schedule-based model groupings provided an opportune time to consider such a change. PGE considered the methods outlined above and chose the independent variable method (3) as the preferred alternative for model testing. The primary reason method (3) was selected rather than the add back method is to keep intact the historical data series and any seasonality or other relationships that may be diminished by adding back imprecise historical savings data.

Model testing found that including a time-series explanatory variable to account for energy efficiency in many of the regression models improved model performance in recent years where energy efficiency savings have shifted from residential to non-commercial. Further, no linear trend interventions were needed in the residential model once the right-hand side energy efficiency variable was included. The third approach also performed well in the small commercial models. Industrial savings are not included as these often reflect large projects, which would largely be captured by the large customer forecast.

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[6] Docket No. UE 394, OPUC Staff Exhibit 900/Gibbens at 7-12.

Q. What is the source of the historical series used as an explanatory variable and forecast for future energy efficiency savings?

A. PGE used historical savings data from ETO's Quarterly and Annual Savings Reports to create a monthly time series of energy efficiency savings by customer type, Residential, Commercial, and Industrial. The energy efficiency time series was tested in each economic model as an independent, right-hand side, variable.

ETO provided a forecast of energy efficiency savings in November 2022. This savings forecast is combined with the historical data provided through the second quarter of 2022 in the ETO's quarterly and annual savings reporting. This forecast is shown in the "EE Savings and Forecast" tab of PGE Exhibit 1101.

Q. What does PGE refer to when using the term Distributed Energy Resources (DERs) in this testimony?

A. PGE considers passive DERs, which are direct, market-driven, customer adoption, including distributed solar and associated storage, electric vehicles, and building electrification end uses as modifiers to its load forecast.

Q. How does PGE account for the impact of DERs in its energy deliveries forecast?

A. PGE's energy deliveries forecast accounts for DERs using an out-of-model adjustment, or trend approach, method (1). This adjustment accounts for incremental impacts beyond those already embedded in PGE's energy deliveries as of October 2022.

Q. Is the DER out-of-model adjustment methodology similar to PGE's prior energy efficiency adjustment?

A. Yes, this adjustment method is like PGE's prior energy efficiency adjustment. DERs are still in early phases of adoption, where the impact on historical savings is much smaller than the projected impact on future savings. For this reason, PGE finds an out-of-model adjustment to be a reasonable and transparent way to reflect the impact of DERs on its energy deliveries forecasts. In the future, as DERs become more engrained in the time series of historical usage data, it may be appropriate to assess a new approach.

Q. What is the source of the DERs forecast?

A. In 2021, a DER forecasting tool was developed to support PGE's DSP process. PGE's Distributed Resource Planning team provided the DER forecast for the 2024 test year based on the latest reference case iteration of its model. This forecast is shown in the "DER Forecast" tab of PGE Exhibit 1101.

Q. What is the impact of incremental DERs on the energy deliveries forecast?

A. In 2024, the total incremental impact for DER is 41 GWh (0.2%). The impact by customer group is shown in the "DER Impact" tab of PGE Exhibit 1101.

IV. Key Forecast Inputs

A. 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 2021. The structure of the model estimates a linear trend fit beginning in 1975. The aim of this approach is not to capture detailed climate science results or to develop a precise forecast for 2024, but rather to capture an unbiased base case weather year 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 1101 shows the degree days used for 2023 and 2024.

Q. Does PGE plan to revise its approach to estimating normal weather conditions in the future?

A. PGE intends to review new data as it becomes available and assess usefulness as an input in the load forecast. In late 2022, PGE worked with Oregon State University's Oregon Climate Change Research Institute to develop a report entitled "Projections of extreme weather for Portland General Electric Company's transmission and distribution system in northwest Oregon." PGE's load forecasting team intends to review the data available in early 2023 to assess appropriateness of use in the load forecast. Further, PGE is participating in Electric Power Research Institute's (EPRI) three-year Climate Readi (REsilience and ADaptation Initiative). This initiative encompasses many topics related to the power sector's approach to managing climate risk to the power system, including an aim to provide industry standard guidance on the use of climate science data in planning.

B. Economic Conditions

Q. What are the most influential economic drivers included in your forecast?

A. The primary economic drivers used in the non-residential energy deliveries models are employment levels. Oregon Total Non-Farm Employment (OENTNA) is included as an explanatory variable in the models for Rate Schedules 32, 83 and 85. 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 primarily linked to economic conditions via the customer count forecast models. PGE new connects are forecasted based on local building permits. As there are no local building permits forecast available in our third-party provided forecasts, PGE creates our own 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.

Q. What is the base case macroeconomic assumption in the 2024 test year forecast?

A. PGE utilizes two sources for macroeconomic assumptions, IHS Markit and OEA. IHS Markit provides U.S. and global economic forecasts while OEA provides a local Oregon forecast. Both entities include a mild economic recession in their reference case macroeconomic forecasts for the 2023-2024 timeframe. This recession is characterized by a slowing in employment growth which impacts PGE's forecasts of deliveries in its rate schedule models.

V. Forecast Results

Q. What are the key results of PGE's residential forecast?

A. For the 2024 test year, we forecast deliveries of 7,903 GWh to 827,210 residential customers. Declines in residential use per customer, driven by incremental energy efficiency programs, are offset by customer growth of 1.1% in 2024, as well as by electrification, for annual energy deliveries increase of 0.7% over 2023. The residential forecast includes residential outdoor area lighting energy. The "Connects" tab of PGE Exhibit 1101 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.

Q. What are the key results of PGE's commercial forecast?

A. For the 2024 test year, we forecast deliveries of 6,932 GWh to general service commercial customers, a 0.8% decrease over forecasted 2023 energy deliveries. Decreases in energy deliveries to the commercial sector are driven by a mild recession beginning in 2023 as well as by energy efficiency. PGE's Exhibit 1101 "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 2024 test year, we forecast deliveries of 7,112 GWh to primary and sub-transmission service customers, 10.5% higher than forecasted 2023 deliveries, following growth of 9.8% in 2023 and 10.3% in 2022. This forecast reflects continued expansion by high-tech and related customers in our service territory. The "Final Forecast," "Non-Residential," and "Large Customer" tabs of Exhibit 1101 show detailed information on this forecast.

Q. What are the key results of PGE's miscellaneous rate schedules forecast?

A. Deliveries to miscellaneous rate schedules account for a very small portion of total retail deliveries. The "Miscellaneous" tab of PGE Exhibit 1101 displays the forecast for miscellaneous schedules, 138 GWh for the 2024 test year.

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 2022 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 2024. 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 1101 tab "COS Direct Access" shows the forecast of deliveries in 2024 to PGE COS customers and direct access (Schedule 485/489/689) customers.

VI. 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 our model, the independent variables include energy efficiency variable, weather variables and the economic forecast drivers. In addition, the model 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 in any given year to include the most recent historical trends, billing data, and input assumptions available. We expect to include a June update and a September update as the final forecast for setting 2024 rates.

VII. 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 energy deliveries forecasting for 13 years. Since joining PGE in 2014, I have worked in the Financial Planning and Forecasting Department, with a focus on load forecasting. Prior to PGE, 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 two years. Prior to joining PGE in 2020, I worked at The Cadmus Group for five years, performing energy efficiency analysis, focusing on economic modeling and statistical analysis.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1101	Base Forecast (prior to DER adjustment)
1102	Final Forecast (after DER adjustment)
1103	Connects
1104	Residential Energy Deliveries
1105	Non-Residential Energy Deliveries
1106	Large Customer Energy Deliveries
1107	Miscellaneous Energy Deliveries
1108	Total System Load and Peak
1109	COS and Direct Access Energy Deliveries
1110	Heating and Cooling Degree Days
1111	Forecast Accuracy
1112	Energy Efficiency Savings and Forecast
1113	DER Impact

Energy Deliveries Forecast (Base[1]) by Service Level

(at average weather)

Base Forecast

	(in GWh)						% Change [2]					
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Residential	7,402	7,764	7,869	7,801	7,848	7,891	-2.0%	4.9%	1.4%	-0.9%	0.6%	0.6%
Residential Area Lighting	2	2	2	2	2	2	-22.0%	-5.6%	0.0%	0.0%	0.0%	-5.9%
Total Residential	7,404	7,765	7,871	7,802	7,850	7,893	-2.0%	4.9%	1.4%	-0.9%	0.6%	0.5%
General Service	7,215	6,721	6,944	6,986	6,975	6,905	-1.2%	-6.8%	3.3%	2.4%	0.0%	-1.0%
Commercial Area Lighting	14	13	12	12	12	12	1.0%	-4.4%	-5.3%	-4.0%	-1.7%	0.0%
Irrigation Service	76	70	91	66	82	82	-16.8%	-7.7%	30.3%	-28.2%	24.7%	0.2%
Street and Traffic Lighting	52	51.8	49	46	44	43	-6.1%	0.0%	-5.4%	-6.7%	-4.6%	-2.3%
Commercial, Secondary Voltage Service	7,356	6,856	7,097	7,109	7,112	7,041	-1.5%	-6.8%	3.5%	0.2%	0.0%	-1.0%
Primary Voltage Service	4,343	4,615	4,989	5,526	6,098	6,775	6.9%	6.3%	8.1%	10.8%	10.3%	11.1%
Sub-Transmission Voltage Service	265	293	324	335	333	334	2.0%	10.5%	10.8%	3.2%	-0.5%	0.2%
Industrial	4,608	4,908	5,314	5,861	6,431	7,109	6.6%	6.5%	8.3%	10.3%	9.7%	10.5%
Total	19,368	19,529	20,281	20,772	21,393	22,043	0.1%	0.8%	3.9%	2.4%	3.0%	3.0%

1) Foreacast results prior to adjustment for DER impacts (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]					
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Residential	7,402	7,764	7,869	7,801	7,843	7,901	-2.0%	4.9%	1.4%	-0.9%	0.5%	0.7%
Residential Area Lighting	2	2	2	2	2	2	-22.0%	-5.6%	0.0%	0.0%	0.0%	-5.9%
Total Residential	7,404	7,765	7,871	7,802	7,845	7,903	-2.0%	4.9%	1.4%	-0.9%	0.5%	0.7%
General Service	7,215	6,721	6,944	6,986	6,990	6,932	-1.2%	-6.8%	3.3%	0.6%	0.1%	-0.8%
Commercial Area Lighting	14	13	12	12	12	12	1.0%	-4.4%	-5.3%	-4.0%	-1.7%	0.0%
Irrigation Service	76	70	91	66	82	82	-16.8%	-7.7%	30.3%	-28.2%	24.7%	0.2%
Street and Traffic Lighting	52	52	49	46	44	43	-6.1%	0.0%	-5.4%	-6.7%	-4.6%	-2.3%
Commercial, Secondary Voltage	7,356	6,856	7,097	7,109	7,127	7,068	-1.5%	-6.8%	3.5%	0.2%	0.3%	-0.8%
Primary Voltage Service	4,343	4,615	4,989	5,526	6,100	6,779	6.9%	6.3%	8.1%	10.8%	10.4%	11.1%
Sub-Transmission Voltage Service	265	293	324	335	333	334	2.0%	10.5%	10.8%	3.2%	-0.5%	0.2%
Indsutrial	4,608	4,908	5,314	5,861	6,433	7,112	6.6%	6.5%	8.3%	10.3%	9.8%	10.6%
Total	19,368	19,529	20,281	20,772	21,405	22,084	0.1%	0.8%	3.9%	2.4%	3.0%	3.2%

1) Final foreacast including adjustment for DER impacts (DEC22D_RATE)

2) Calculated from rounded numbers

Residential Building Permits, New Connects, Vacancy Rates and Customer Counts

	2019	2020	2021	2022 [1]	2023	2024
Building Permits [2]						
Single-Family	10,087	10,480	11,717	10,437	9,049	10,135
Multi-Family	10,756	6,932	8,878	9,063	9,752	9,581
New Connects						
Single-Family	4,908	4,561	4,801	4,792	4,554	4,657
Multi-Family	5,430	6,225	4,990	4,209	5,149	5,383
Mobile Home	123	119	91	82	96	96
Other	233	276	221	180	180	180
Total Residential Connects	10,694	11,181	12,601	10,103	9,979	10,316
Commercial Connects	2,619	2,402	2,498	2,456	1,988	2,257
Total New Connects	13,313	13,583	15,099	12,559	11,967	12,573
Residential Customer Counts						
Single-Family	485,602	490,672	494,397	498,610	502,442	506,370
Multi-Family	257,495	263,543	268,812	273,759	278,108	283,517
Mobile Home	34,826	34,911	34,915	34,891	34,844	34,832
Other	1,750	2,028	2,231	2,381	2,471	2,491
Total Number of Accounts [3]	779,673	791,154	800,355	809,641	817,865	827,210

1) Includes actuals through December 2022, except for connects which include actuals through June 2022

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

	2019	2020	2021	2022	2023	2024	2019	2020	2021	2022	2023	2024
Use per Customer (kWh)												
Single-Family Heat	10,541	10,956	10,980	10,699	10,719	10,688	-2.4%	3.9%	0.2%	-2.6%	0.2%	-0.3%
Multiple-Family Heat	7,063	7,261	7,298	7,255	7,135	7,110	-3.9%	2.8%	0.5%	-0.6%	-1.7%	-0.4%
Mobile Home Heat	12,954	13,094	13,142	13,098	13,071	13,071	-2.8%	1.1%	0.4%	-0.3%	-0.2%	0.0%
Other	7,430	8,393	8,833	9,563	7,243	7,191	-28.4%	13.0%	5.2%	8.3%	-24.3%	-0.7%
Average Use per Customer	9,494	9,815	9,834	9,637	9,592	9,554	-2.9%	3.4%	0.2%	-2.0%	-0.5%	-0.4%
Ultimate Deliveries (in GWh)												
Single-Family Heat	5,119	5,376	5,429	5,335	5,386	5,412	-1.6%	5.0%	1.0%	-1.7%	1.0%	0.5%
Multiple-Family Heat	1,819	1,914	1,962	1,986	1,984	2,016	-2.4%	5.2%	2.5%	1.2%	-0.1%	1.6%
Mobile Home Heat	451	457	459	457	455	455	-2.8%	1.3%	0.4%	-0.4%	-0.4%	0.0%
Other	13	17	20	23	18	18	-51.3%	30.8%	15.9%	15.7%	-21.5%	0.0%
Schedule 7 Deliveries	7,402	7,764	7,869	7,801	7,843	7,901	-2.0%	4.9%	1.4%	-0.9%	0.5%	0.7%
Residential Lighting	2	2	2	2	2	2	-13.4%	-15.0%	0.0%	0.0%	0.0%	-5.9%
Total Residential Deliveries	7,404	7,765	7,871	7,802	7,845	7,903	-2.0%	4.9%	1.4%	-0.9%	0.5%	0.7%

Non-Residential Energy Deliveries Forecast by Rate Schedule

(at average weather)

Net of Incremental Distributed Energy Resources, Excluding Large Customers

	(in GWh)						% Change [1]					
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Schedule 32	1,586	1,491	1,528	1,538	1,558	1,546	-2.5%	-6.0%	2.5%	0.7%	1.3%	-0.8%
Schedule 38	32	26	27	27	27	27	-1.1%	-20.2%	6.2%	0.0%	0.0%	0.0%
Schedule 83	2,873	2,712	2,829	2,912	2,885	2,878	-1.9%	-5.6%	4.3%	2.9%	-0.9%	-0.2%
Schedule 85 [2]	3,520	3,226	3,195	3,207	3,225	3,173	2.3%	-8.3%	-1.0%	0.4%	0.6%	-1.6%
Schedule 89 [2]	297	312	380	387	392	389	-12.8%	5.0%	21.6%	2.0%	1.2%	-0.8%
Total Non-Residential	8,308	7,767	7,959	8,072	8,087	8,012	-0.7%	-6.5%	2.5%	1.4%	0.2%	-0.9%

1) Calculated using rounded-numbers

2) Excluding individually forecasted large customers

Large Customer Deliveries Forecast by Rate Schedule

	(in GWh)						% Change [1]					
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Schedule 85	206	249	215	192	233	317	-2.2%	20.8%	-13.6%	-10.9%	21.4%	36.2%
Schedule 89	1,312	1,343	1,542	1,847	2,146	2,514	2.8%	2.4%	14.8%	19.8%	16.2%	17.1%
Schedule 90	1,997	2,270	2,543	2,736	2,957	3,201	12.8%	13.6%	12.0%	7.6%	8.1%	8.2%
Total Large Customer	3,516	3,862	4,300	4,775	5,336	6,032	7.9%	9.8%	11.3%	11.1%	11.8%	13.0%

1) Calculated using rounded-numbers

Forecast of Energy Deliveries to Miscellaneous Rate Schedules

	(in GWh)						% Change [1]					
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Residential												
Outdoor Area Lighting [2]	1.8	1.7	1.7	1.7	1.7	1.6	-21.7%	-5.6%	0.0%	0.0%	0.0%	-5.9%
Commercial												
Outdoor Area Lighting [3]	13.7	13.1	12.4	11.9	11.7	11.7	0.7%	-4.4%	-5.3%	-4.0%	-1.7%	0.0%
Farm Irrigation et al. [4]	75.8	70.0	91.2	65.5	81.7	81.9	-16.8%	-7.7%	30.3%	-28.2%	24.7%	0.2%
Street and Other Lighting [5]	51.8	51.8	49.0	45.7	43.6	42.6	-6.0%	0.0%	-5.4%	-6.7%	-4.6%	-2.3%
All Miscellaneous Schedules	143	137	154	125	139	138	-11.7%	-4.5%	12.9%	-19.1%	11.1%	-0.6%

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]
2015	19,651	2,344	3,914
2016	19,147	2,287	3,726
2017	19,221	2,389	3,976
2018	19,344	2,322	3,816
2019	19,368	2,343	3,765
2020	19,529	2,348	3,771
2021	20,281	2,464	4,453
2022	20,772	2,551	4,255
2023	21,405	2,599	4,077
2024	22,084	2,682	4,154

1) Cycle basis, at the meter, actual through 2022, weather normalized.

2) Calendar basis, at the bus bar, actual through 2022, not adjusted for weather.

3) Coincidental annual system peak at bus bar; includes actual through 2022, not adjusted for weather.

Forecast of 2024 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	7,903	0	7,903
Secondary	6,599	427	7,026
Primary	5,136	1,643	6,779
Sub-Transmission	56	278	334
Lighting	43	0	43
Total Retail [2]	19,736	2,348	22,084

1) Includes economic replacement VPO deliveries

2) Schedule 485/489/689 deliveries

3) Totals may not add due to rounding

Degree Day Variables

	2023		2024	
	HDD65	CDD65	HDD65	CDD65
January	765	-	763	-
February	645	-	644	-
March	560	-	560	-
April	410	-	408	-
May	251	10	249	10
June	121	43	120	43
July	40	136	40	137
August	11	232	11	234
September	23	174	23	176
October	125	38	123	39
November	341	-	339	-
December	654	-	653	-
Annual	3,946	633	3,933	639

Summary of PGE Forecast Error to Itron Benchmarking Survey[1]

	2011		2012		2013		2014		2015		2016	
	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%
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%
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%
System	NA	-0.5%	1.6%	-1.5%	1.5%	-2.5%	1.3%	0.6%	1.9%	1.5%	1.6%	-1.4%

	2017		2018		2019		2020		2021		2022	
	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE
Residential	1.4%	-1.3%	1.8%	-0.5%	1.2%	-2.2%	3.8%	4.2%	2.4%	4.2%	N/A	2.7%
Commercial	1.3%	0.3%	2.0%	1.1%	1.7%	-1.0%	6.5%	-7.0%	3.1%	3.0%	N/A	-1.2%
Industrial	2.3%	2.0%	1.9%	0.7%	4.1%	4.8%	8.3%	2.6%	3.1%	5.4%	N/A	0.5%
System	1.1%	0.0%	1.3%	0.4%	1.4%	-0.2%	3.1%	0.4%	1.7%	4.1%	N/A	0.8%

1) Itron Benchmarking Survey released annually, usually via free brown bag webinar. https://www.itron.com/na/blog/forecasting/annual-forecasting-benchmarking-survey-results

Energy Efficiency Forecast

	(in GWh)					% Change [1]				
	2020	**2021**	**2022 [2]**	**2023 [3]**	**2024 [3]**	**2020**	**2021**	**2022 [2]**	**2023 [3]**	**2024 [3]**
Residential EE Savings	79	87	92	97	101	9.8%	9.2%	6.5%	4.8%	4.8%
Commercial EE Savings	102	110	117	124	131	10.0%	8.2%	6.6%	5.5%	5.8%
Indutrial EE Savings	76	83	91	99	105	11.4%	8.4%	9.7%	8.7%	6.8%
Total EE Savings	257	279	300	319	337	10.3%	8.6%	7.4%	6.2%	5.8%

1) Calculated using rounded-numbers

2) Calculated using quarterly actuals through Q2 2022

3) ETO forecast provided in November 2022

Distributed Energy Resources

Annual Incremental Forecast (in GWh)

	2023	2024
Building Electricification	15.9	42.2
Transportation Electricification	30.6	82.2
Storage	(0.0)	(0.0)
Rooftop Solar	(34.0)	(83.4)
Total Residential Impact	(4.5)	10.1
Total Commercial Impact	16.9	30.8
Total Impact	12.4	41.0

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Robert Macfarlane
Ashleigh Keene

February 15, 2023

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Robert Macfarlane. I am Manager, Pricing and Tariffs at Portland General Electric Company (PGE). I am responsible, along with Ms. Keene, for the development of the marginal cost studies.

My name is Ashleigh Keene. I am a Regulatory Consultant 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 generation, transmission, distribution, customer service, and street lighting marginal cost of service studies. PGE Exhibit 1201 provides a summary of these marginal costs by component. The summary lists costs by PGE 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 1201.

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 1201.

II. Generation Marginal Cost Study

Q. What methodology do you propose for estimating generation marginal costs in this docket?

A. We propose a long-run generation methodology that explicitly estimates the cost of marginal generation capacity and long-run marginal energy, reflective of future resources that are non-carbon emitting. Prior generation marginal cost studies, starting with PGE's 2016 general rate case (GRC) Docket No. UE 294 and continuing in Docket Nos. UE 319, UE 335, and UE 394, incorporated a renewable resource component into long-run marginal energy costs; however, this is PGE's first study that is based solely on non-carbon emitting resources for both marginal generation capacity and long-run marginal energy costs. With the passage of Oregon House Bill 2021 (Clean Energy Targets) and PGE's commitment to decarbonization, PGE is currently planning for future resources that support our greenhouse gas emissions reduction goal of 80% by 2030.

The specific wind and storage resources used in this analysis are not indicative of PGE's broader approach to meeting future customer demand, one that also includes continued energy efficiency, demand response and community and customer-sited solar, among others. Utility scale wind and battery storage provide a simplified proxy for cost allocation that yields results approximate of those from legacy generation marginal cost studies. This is important because an extreme departure from the recent cost estimates could have sharp or abrupt price impacts on certain customer classes.

Q. How is the methodology in this proceeding that is used to develop the long-run generation allocation different from PGE's 2022 GRC, Docket No. UE 394?

A. The legacy methodology used to develop the overall long-run marginal generation allocation in PGE's 2022 GRC (Docket No. UE 394) was based on a weighted[1] average of costs for a combined cycle combustion turbine (CCCT) and a wind resource. Recognizing that generation resources bring both energy and capacity value to PGE's system, the marginal energy value for the CCCT was isolated from the marginal generation capacity value by using a capacity-only proxy—a simple cycle combustion turbine (SCCT)—to approximate the CCCT's embedded capacity value. The marginal energy value of the CCCT was thus estimated to be the full value of the CCCT minus the capacity value of the SCCT. The wind resource used in the 2022 GRC was assumed to provide only energy-related value.

The current methodology for long-run generation uses wind as the sole resource to estimate the marginal cost of energy and continues the assumption that 100% of its value is energy-related. Utility-scale battery storage is used to estimate marginal generation capacity costs.

Q. Why is the capacity value for wind resources not recognized in PGE's current long-run generation marginal cost study?

A. While PGE recognizes that wind resources add capacity value to its system, there are reasons to exclude it from the methodology used to estimate marginal energy costs in this rate case. First, isolating the embedded capacity value of wind resources in capacity considerations will reduce their marginal energy value. Since replacing SCCTs with utility-scale battery storage will already result in higher marginal generation capacity costs, decreasing the true marginal

[1] The weighting reflected Oregon's 2022 Renewable Portfolio Standard.

energy value of a wind resource puts additional pressure on prices for weather-sensitive customer classes like residential and small commercial customers. Second, it is important to maintain relative consistency with prior cost studies and temper the amount of change introduced at a time when we are making a significant shift in proxy resource selection, from carbon emitting to non-carbon emitting, to mitigate large shifts in cost allocation and customer prices.

Q. What are the sources of the overnight capital costs for the resources used in the model?

A. Transmission is a key component for many renewable resources which may be sited in areas more optimal for wind or solar generation and associated costs should be reflected in long-run marginal energy estimates. The proxy long-run energy resource is a wind facility. Overnight capital costs, as well as operation and management (O&M) expenses, are sourced from the recently awarded bid for the PGE-owned portion of the future Clearwater wind facility in Montana.

We decided to use the awarded bid instead of the draft Integrated Resource Plan (IRP) and Clean Energy Plan (CEP) generic resource costs because the former provides a more reasonable proxy for a near-term construction. Current IRP/CEP costs are based on publicly available data from the Department of Energy's National Renewable Energy Laboratory and do not account for near-term, regional supply chain issues that impact capital project costs for a proxy resource coming online in 2024. Additionally, at the time of preparing testimony, PGE's IRP/CEP process was still finalizing cost assumptions for required transmission for energy delivery to PGE's system and, thus, were not available for inclusion in this study. The IRP/CEP filing will be submitted to the Commission by March 31, 2023.

The proxy capacity resource is a generic 4-hour utility-scale battery. For the reasons mentioned above, PGE preferred to use an awarded capacity bid for the assessment of generation capacity value as well, but a selection had not yet been awarded at the time of study preparation. Overnight capital costs[2] are instead sourced from interim results for PGE's 2023 IRP/CEP.

Q. Did you include production tax credits or investment tax credits in your analysis?

A. Yes. With 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 resource 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 $138.52 per kilowatt year (kW-yr) in real levelized 2024 dollars. The cost of the wind resource, inclusive of fixed transmission costs required to bring the energy to PGE's system, is estimated at $56.24 per megawatt hour (MWh) in real levelized 2024 dollars.

Q. How do you estimate each rate schedule's marginal cost of capacity?

A. 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. 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?

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[2] Cost of the project as if no interest were included during its construction.

A. We shape the annual long-run marginal energy cost 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 Annual Update Tariff filing under Docket No. UE 402, Exhibit 100, for a description of MONET.

III. Transmission Marginal Cost Study

Q. Have you performed a transmission unit marginal costs analysis for this docket?

A. Yes. The methodology is the same that was used in Docket No. UE 394. Based on the transmission projects and transmission substation marginal costs provided in PGE Exhibit 1202, we calculate a unit marginal cost of $87.34 per kW (shown in Column (A) on page 3 in PGE Exhibit 1201).

Q. Is PGE a transmission-dependent utility?

A. Yes. PGE is a transmission-dependent utility that purchases about 3,700 megawatts (MW) of transmission from Bonneville Power Administration (BPA) to integrate its generation and purchased power. PGE operates a limited transmission system comprised of approximately 268 pole miles of 500 kilovolts (kV) lines and 270 pole miles of 230 kV lines, some of which are functionalized to generation. At the 230 kV level, the system ties into seven BPA bulk power substations around the Portland area. PGE also has ties into three BPA bulk power substations in the Salem area. The primary function of the 230 kV system that is functionalized to transmission is to provide an interface to the main grid for load service.

Q. What drives additions to PGE's existing transmission system?

A. PGE's transmission planners evaluate whether additions to PGE's existing transmission system are needed to meet North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) reliability standards for serving customers based on 1-in-3 peak load conditions during the summer and winter seasons for both the near term and the long-term.[4] The winter period is defined as November 1st through March 31st, and the summer is defined as June 1st through October 31st, totaling ten months in all. Because

[4] *See* "PGE's Near Term Local Transmission Plan for the 2022-2023 Planning Cycle," provided as Exhibit 1202.

the transmission planners use ten months of peak loads when evaluating reliability, we extend the peak load criteria slightly to twelve months when calculating unit marginal costs. A twelve-month coincident peak (12CP) is also consistent with how the Federal Energy Regulatory Commission (FERC) determines PGE's Open Access Transmission Tariff prices.

IV. Distribution Marginal Cost Study

Q. Which marginal distribution costs do you calculate?

A. We calculate marginal distribution costs separately for subtransmission, substations, distribution feeders (backbone facilities and local facilities), line transformers (including services), and meters.

Q. How do you calculate the marginal unit costs of subtransmission and substations?

A. We calculate subtransmission unit costs by first summing growth-related capital expenditures over the five years between 2020-2024. We then annualize these capital expenditures and divide them by the growth in system non-coincident peak (NCP). Customers served at subtransmission voltage are excluded from this calculation because they supply their own substation. We calculate substation marginal costs using a recent engineering estimate of the cost to construct a substation. We then divide the cost by the substation transformer capacity in kW and annualize the cost per kW. Columns (B) and (C) on page 3 of PGE Exhibit 1201 summarizes subtransmission and substation costs.

Q. How do you calculate the marginal unit feeder costs?

A. We estimate distribution feeder unit costs in the following manner:

1. Perform an analysis that places customers by class on the distribution feeder from which they are currently served.
2. Eliminate any distribution feeders from which we cannot obtain customer information, and which do not conform to "typical" standards. Examples of these "non-typical" feeders are feeders serving customers at 4 kV and feeders that serve downtown core areas.

3. Perform an inventory of the wire types and sizes for each feeder. Standardize these wire types and sizes to current specifications and then calculate the cost of rebuilding these feeders in today's dollars.
4. Segregate the wire types and sizes into mainline feeders and taplines. Mainline feeders are typically capable of carrying larger loads and are typically closer to the substations from which they originate. Taplines are typically capable of carrying smaller loads and can be remote from substations.
5. For each feeder, allocate the mainline cost responsibility of each customer class based on the customer class's proportionate contribution to NCP. Calculate a unit cost per kW by totaling the feeder cost responsibilities and dividing by the sum of each class's NCP.
6. For each feeder, allocate the tapline cost responsibility of each customer class based on its proportionate design demand (estimated peak at the line transformer). Calculate a unit cost per kW for both poly- and single-phase customers by totaling the feeder cost responsibilities and dividing by the sum of each schedule's design demand.
7. Annualize the mainline and tapline unit costs by applying an economic carrying charge.
8. Separately estimate the unit costs of customers with peak loads greater than 4 MW who are typically on dedicated distribution feeders. Calculate these marginal unit costs per customer as the average distance between the substation and the customer-owned facilities. Finally, apply the annual carrying charge to annualize the cost per customer.

9. Separately estimate the per-customer costs of customers served at subtransmission voltage. This is done by first calculating the average distance from the point at which subtransmission voltage customers connect to the subtransmission system from their substation. Then we multiply this average distance by the current cost per wire mile and annualize the costs.

Columns (D) and (E) on page 3 of PGE Exhibit 1201 summarize feeder mainline and tapline costs.

Q. Why do you propose to calculate the marginal costs of feeders based on class size rather than by rate schedule?

A. We propose this because past marginal feeder costs analyses have resulted in extremely high unit marginal costs for irrigation Schedules 47 and 49 due to their preponderant location on remote feeders within PGE's service territory. This cost result for the irrigation schedules seems to be due to geographical distinction rather than due to economies of scale. Because PGE does not price by geographical area, we propose the class size distinction when calculating unit marginal feeder costs. For all other marginal cost categories, we separately measure the unit marginal costs of the irrigation schedules.

Q. Please describe any other considerations when calculating unit feeder costs.

A. Currently, many municipalities require undergrounding of taplines within subdivisions and commercial areas. Therefore, we used the current cost of underground facilities exclusively in our marginal feeder tapline cost calculations.

Q. How do you calculate secondary tapline costs?

A. We estimate the percentage of time field personnel spend on maintaining secondary service conductors. After estimating the approximate $3.3 million costs of maintaining secondary service conductors by the appropriate Accounting Work Order (AWO), we deduct the estimated secondary service conductor maintenance cost amounts from the total of the FERC maintenance amounts. Then, for the appropriate cost categories, we allocate the amount of expense attributable to primary voltage and secondary voltage conductors by the objective measure of relative circuit wire miles. This decomposition of the FERC maintenance accounts is contained in the feeder O&M work papers accompanying this testimony. In addition to the allocation of maintenance costs described above, we reassigned approximately $51,000 in transformer costs from overhead and underground line maintenance to the transformer maintenance account.

Column (F) on page 3 of PGE Exhibit 1201 summarizes secondary distribution facilities costs.

Q. How do you calculate marginal transformer and service costs?

A. We calculate each schedule's marginal transformer and service costs by estimating the cost of providing the average customer within specific load sizes with a service lateral and a line transformer (secondary delivery voltage only). For smaller customers such as those on Schedules 7 and 32, we estimate the average number of customers on a transformer to appropriately calculate the per customer share of transformer costs. Column (G) on page 3 of PGE Exhibit 1201 summarizes transformer and service costs.

Because primary and subtransmission voltage customers supply their own transformers and service laterals, the marginal cost for these customers is zero.

Q. Please describe how you calculate the marginal costs of meters.

A. We calculate marginal meter costs as the weighted installed cost of an Advanced Metering Infrastructure (AMI) meter for each rate schedule or load size, and then apply an annual carrying charge. Column (H) on page 3 of PGE Exhibit 1201 summarizes meter costs.

Q. How do you allocate distribution O&M to each distribution category and ultimately to each rate schedule?

A. We allocate test-period distribution O&M by distribution category to the rate schedules in proportion to each schedule's respective usage and per unit marginal capital cost. All of the distribution costs by functional category, on page 3 of PGE Exhibit 1201, are inclusive of test-period distribution O&M.

Q. Why does PGE split out the distribution marginal costs for residential single-family and residential multi-family in its distribution marginal cost study?

A. PGE has a differentiated Basic Charge amount for single-family and multi-family residential customers reflecting the difference in marginal cost to serve these two customer types and allocates fixed costs appropriately. This amount is included in Exhibit 1201.

Q. How did PGE split out the distribution marginal costs for residential single-family and residential multi-family in its distribution marginal cost study?

A. Using PGE's residential customer data, PGE identifies the number of residential customers that live in single-family versus multi-family housing, where multi-family is defined as housing with three or more attached units, including apartments, condominiums, or townhomes, typically equipped with multiple meters. Separate marginal costs for each residential subgroup are calculated for the Feeder Mainline, Feeder Tapline, Secondary

Tapline, and Transformer & Service costs. Marginal costs for Transmission, Subtransmission, Substation, and Meter costs do not differ among residential customers.

V. Customer Service Marginal Cost Study

Q. What is the purpose of the customer service marginal cost study?

A. The purpose of the customer service marginal cost study is to calculate the incremental cost of customer service for each rate schedule. PGE incurs costs in managing its relationship with customers, including handling customer communications, measuring usage, maintaining records, and billing. As such, customer service costs increase as the number of customers PGE serves increases. Column (I) on page 3 of PGE Exhibit 1201 summarizes marginal customer costs.

Q. Does PGE use the forecasted test year expenses in the customer marginal cost study?

A. Yes. PGE uses forecasted costs for the 2024 test period and 2022 actual costs to develop the 2024 test year customer service marginal cost study. These costs are found in FERC Account Nos. 902, 903, 905, 908, and 909. The 2024 forecasted costs are also referred to as budget amounts in this testimony.

Q. Is the study's methodology the same as in PGE's last general rate case UE 394?

A. Yes. The methodology is the same except for two minor adjustments. The first is a small adjustment to the allocation methodology for Retail Receivables and Field Collections, which is based on the three-year average of adjusted write-offs. As such, it would be anticipated that these allocations would be based on 2020, 2021, and 2022, but due to abnormalities in write-offs caused by the COVID-19 pandemic in these years, 2017, 2018, and 2019 are being used instead, as these years are more indicative of the write-offs that PGE anticipates. The second minor change is made to the allocation of Communication and Customer Insights within the Other Expenses category. These expenses are no longer being allocated to lighting customers (Schedules 15, 91, 92, and 95) as these departments do no work directly attributable to lighting, so it is not appropriate to allocate these costs to lighting customers. As in UE 394, the remaining costs are allocated to PGE accounts directly based on cost causation. A few accounts are allocated based on a sub-allocation of the other account costs. After the costs are spread across rate schedules, the final result is marginal costs for each rate schedule by each of the three functionalized categories: metering, billing, and other services.

Q. Please provide an example of how you calculate metering marginal costs.

A. The 2024 forecasted amount for FERC Account No. 902, Field Collection Department, is allocated based on manual meter reads and a weighted percentage of customers (less unmetered lighting and signals).

Q. Please provide examples of how you calculate billing marginal costs.

A. Examples include:

- The costs for Retail Receivables and Field Collections are allocated based on the percentage of adjusted write-offs by rate schedule.
- Customer Service billing costs are allocated by the number of customers.
- The costs for Printing and Automated Mail Services are allocated based on the number of paper bills delivered.
- Advanced Metering Infrastructure costs are allocated based on the number of customers with meters, which excludes unmetered lighting and traffic signals.

Q. Please provide examples of how you calculate other customer service marginal costs.

A. Examples include:

- The budget amount associated with the Customer Contact Operations is allocated by the number of customers on rate schedules using up to 200 kW.

- The budget amount for the Direct Access Operations Department is allocated by the number of customers participating in the direct access program.
- The Solar Payment Option and Net Metering Operations budget amounts are allocated by the number of customers participating in the programs.

VI. 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 propose to 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 (2018 to 2022). 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 1305.

VII. 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. Keene, please state your educational background and qualifications.

A. I received a Master of Science degree in Applied Economics from the University of Wisconsin—Madison. Since joining PGE in 2018, I have worked in the Rates and Regulatory Affairs Department, with a focus on load research, time-variant rates and rate affordability. Prior to PGE, I worked as a consultant at the Energy Center of Wisconsin (now Slipstream), where I conducted evaluations for demand response and weatherization programs, and at the McDowell Group (now McKinley Research) in Juneau, Alaska, where I focused on economic and community impact analyses.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
1201	Marginal Cost Study
1202	Portland General Electric Company's Near Term Local Transmission Plan for the 2022-2023 Planning Cycle

PORTLAND GENERAL ELECTRIC
2024 MARGINAL ENERGY COSTS

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	8,440,501	$495,515,868
Schedule 15	14,235	$706,401
Schedule 32	1,650,783	$96,123,812
Schedule 38	29,138	$1,727,555
Schedule 47	22,560	$1,412,400
Schedule 49	64,916	$4,108,087
Schedule 83	3,073,234	$179,585,403
Schedule 85	2,933,588	$170,742,562
Schedule 89	1,389,738	$78,884,656
Schedule 90-P	3,399,595	$190,662,100
Schedule 91/95	42,547	$2,111,364
Schedule 92	2,907	$166,021
TOTALS	21,063,741	$1,221,746,229

PORTLAND GENERAL ELECTRIC
2022 MARGINAL ENERGY AND CAPACITY COSTS

Year	Marginal Capacity $/kW-year	Marginal Energy $/MWh
2024	138.52	56.24
2025	141.47	57.44
2026	144.48	58.67
2027	147.56	59.92
2028	150.70	61.19
2029	153.91	62.50
2030	157.19	63.83
2031	160.54	65.19
2032	163.95	66.57
2033	167.45	67.99
2034	171.01	69.44
2035	174.66	70.92
2036	178.38	72.43
2037	182.18	73.97
2038	186.06	75.55
2039	190.02	77.16
2040	194.07	78.80
2041	198.20	80.48
2042	202.42	82.19
2043	206.73	83.94
NPV	$2,199	$893
Nominal Levelized	$199.31	$80.93
Real Levelized	$138.52	$56.24

Composite Tax Rate	26.97%		
Property Tax Rate (OR)	1.47%		
Property Tax Rate (MT)	2.23%		
Property Tax Escalation Rate	0.00%		
Minimum Book Value for Property Tax	0.00%		
Inflation Rate	2.13%		
Target Capital Structure			
Preferred	0.00%	0.00%	0.00%
Common	50.00%	9.80%	4.90%
All Equity	50.00%	9.80%	4.90%
Debt	50.00%	4.33%	2.17%
Wtd. Avg. Cost of Capital	100.00%		7.07%
After-Tax Nominal Cost of Capital			6.48%
After-Tax Real Cost of Capital			4.26%

PORTLAND GENERAL ELECTRIC
SUMMARY OF TRANSMISSION, DISTRIBUTION AND CUSTOMER MARGINAL COST STUDIES

SCHEDULE	TRANSMISSION COSTS ($/kW)	SUBTRANSMISSION COSTS ($/kW)	SUBSTATION COSTS ($/kW)	FEEDER MAINLINE COSTS ($/kW)	FEEDER TAPLINE COSTS ($/kW)	SECONDARY TAPLINE COSTS ($kW)	TRANSFORMER & SERVICE COSTS ($/Customer)	METER COSTS ($/Customer)	CUSTOMER COSTS ($/Customer)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Schedule 7 Residential									
Single-phase	$87.34	$1.33	$15.88	$40.80	$46.23	$5.87	$116.40	$21.08	$50.62
Single-Family	$87.34	$1.33	$15.88	$46.67	$56.60	$7.19	$118.06	$21.08	$50.62
Multi-Family	$87.34	$1.33	$15.88	$29.15	$25.64	$3.34	$82.11	$21.08	$50.62
Three-phase	$87.34	$1.33	$15.88	$40.80	$46.23	$5.87	$154.70	$47.38	$50.62
Schedule 15 Residential	$87.34	$1.33	$15.88	$43.89	$48.69	$3.34	$3.28	N/A	$2.15
Schedule 15 Commercial	$87.34	$1.33	$15.88	$43.89	$48.69	$3.34	$3.28	N/A	$1.80
Schedule 32 General Service									
Single-phase	$87.34	$1.33	$15.88	$50.12	$73.97	$4.70	$232.99	$43.59	$52.09
Three-phase	$87.34	$1.33	$15.88	$50.12	$19.75	$1.26	$317.24	$61.01	$52.09
Schedule 38 TOU									
Single-phase	$87.34	$1.33	$15.88	$52.07	$89.70	$3.42	$224.52	$50.04	$248.10
Three-phase	$87.34	$1.33	$15.88	$52.07	$22.49	$0.86	$745.21	$100.38	$248.10
Schedule 47 Irrigation									
Single-phase	$87.34	$1.33	$15.88	$50.12	$73.97		$34.20	$50.54	$46.02
Three-phase	$87.34	$1.33	$15.88	$50.12	$19.75		$50.84	$70.05	$46.02
Schedule 49 Irrigation									
Single-phase	$87.34	$1.33	$15.88	$52.07	$89.70		$317.26	$50.54	$247.01
Three-phase	$87.34	$1.33	$15.88	$52.07	$22.49		$317.27	$60.83	$247.01
Schedule 83 Secondary General Service									
Single-phase	$87.34	$1.33	$15.88	$52.07	$89.70	$3.42	$516.67	$50.54	$360.77
Three-phase	$87.34	$1.33	$15.88	$52.07	$22.49	$0.86	$1,282.21	$105.82	$360.77
Schedule 85 Secondary General Service	$87.34	$1.33	$15.88	$42.18	$7.37		$2,893.64	$113.81	$1,464.91
Schedule 85 Primary General Service	$87.34	$1.33	$15.88	$42.18	$7.37		$0.00	$1,795.89	$1,464.91
Schedule 89 Secondary	$87.34	$1.33	$15.88	$104,332 ($/Customer)	N/A		$17,546.57	$113.81	$8,346.49
Schedule 89 Primary	$87.34	$1.33	$15.88	$104,332 ($/Customer)	N/A		$0.00	$1,896.75	$8,346.49
Schedule 89 Subtransmission	$87.34	$1.33	N/A	$93,301 ($/Customer)	N/A		N/A	$17,623.44	$8,346.49
Schedule 90 Primary	$87.34	$1.33	$15.88	$491,171 ($/Customer)	NA		$0.00	$1,896.75	$35,020.81
Schedule 90 Subtransmission	$87.34	$1.33	$15.88	$93,301 ($/Customer)	N/A		N/A	$17,623.44	$35,020.81
Schedules 91 & 95 Streetlighting	$87.34	$1.33	$15.88	$43.89	$48.69	$6.19	$3.28	N/A	$213.87
Schedules 92 Traffic Signals	$87.34	$1.33	$15.88	$43.89	$19.13	$0.12	$6.33	N/A	$198.04

Portland General Electric Company's Near Term Local Transmission Plan For the 2022-2023 Planning Cycle

FINAL - November 16, 2022

Contents

1. Introduction

This 2022 Near Term Local Transmission Plan reflects Quarters 1 through 4 of the local transmission planning process as described in PGE's Open Access Transmission Tariff (OATT) Attachment K. The plan includes all transmission system facility improvements identified through this planning process. A power flow reliability assessment of the plan was performed which demonstrated that the planned facility additions will meet NERC and WECC reliability standards.

PGE's OATT is located on its Open Access Same-time Information System (OASIS) at http://oasis.oati.com/PGE. Additional information regarding Transmission Planning is located in the *Transmission Planning* folder on PGE's OASIS. Unless otherwise specified, capitalized terms used herein are defined in PGE's OATT.

1.1. Local Planning

This Local Transmission Plan (LTP) has been prepared within the two-year process as defined in PGE's OATT Attachment K. The LTP identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, including both grandfathered, non-OATT agreements and rollover rights, over a ten (10) year planning horizon. Additionally, the LTP typically incorporates the results of any stakeholder-requested economic congestion studies results that were performed. However, none were requested or incorporated during this particular cycle.

1.2. Regional and Interregional Coordination

PGE coordinates its planning processes with other transmission providers through membership in NorthernGrid and the Western Electric Coordinating Council (WECC). PGE uses the NorthernGrid process for regional planning, coordination with adjacent regional groups and other planning entities for interregional planning, and development of proposals to WECC. Additional information is located in PGE's OATT Attachment K, in our Transmission Planning Business Practice on OASIS, and on NorthernGrid's website at www.northerngrid.net.

2. Planning Process and Timeline

This plan is for the 2022-2023 planning cycle. PGE's OATT Attachment K describes an eight (8) quarter study and planning cycle. The planning cycle schedule is shown below in Figure 1.

Figure 1: PGE OATT Attachment K Eight Quarter Planning Cycle

		Quarter	Tasks
Near Term	Even Years	1	Select Near Term base cases and gather load data
		2	Post Near Term methodology on OASIS, select one Economic Study for evaluation
		3 & 4	Select Longer Term base cases, post draft Near Term Plan on OASIS, hold public meeting to solicit stakeholder comment
		4	Incorporate stakeholder comments and post final Near Term plan on OASIS
Longer Term	Odd Years	5	Gather load data and accept Economic Study requests
		6	Select one Economic Study for evaluation
		7 & 8	Post draft Longer Term plan on OASIS, hold public meeting to solicit stakeholder comment
		8	Post final Longer Term plan on OASIS, submit final Longer Term Plan to stakeholders and owners of neighboring systems

PGE updates its Transmission Customers about activities and/or progress made under the Attachment K planning process, during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the *Customer Meetings* folder on PGE's OASIS.

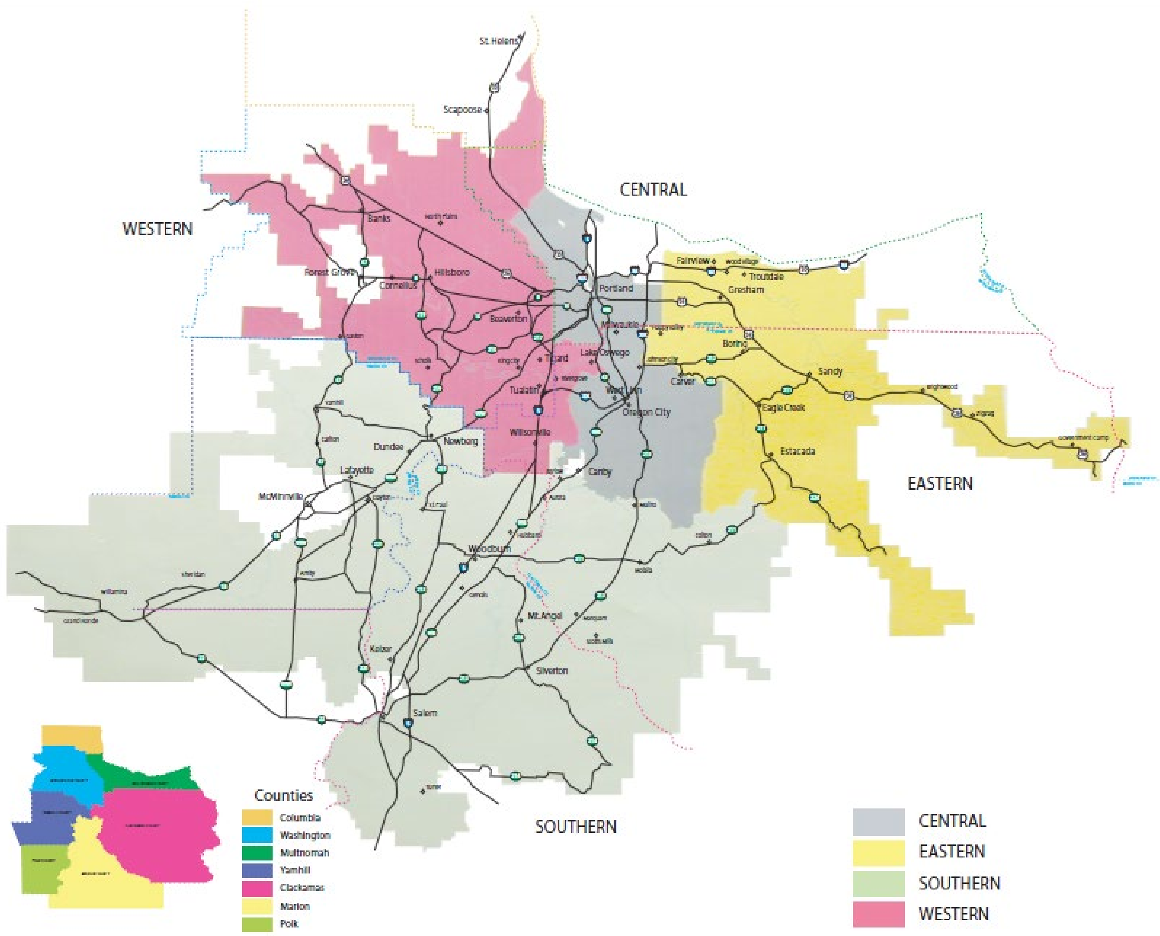
Meeting dates are posted on PGE's OASIS.

3. Transmission System Plan Inputs and Components

3.1. PGE's Transmission System

Portland General Electric's (PGE) service territory covers 4,000 square miles and provides service to over 880,000 customers. PGE's service territory is confined within Multnomah, Washington, Clackamas, Yamhill, Marion, and Polk counties in northwest Oregon, as shown in Figure 2.

Figure 2: Map of PGE's Service Territory



PGE's Transmission System is designed to reliably distribute power throughout the Portland and Salem regions for the purpose of serving native load and integrating transmission and generation resources on the Bulk Electric System. The following PGE-owned 500 kV and 230 kV lines are essential elements of regional transmission paths:

> The Grizzly BPA-Malin BPA #2 500 kV line and the Grizzly BPA-Round Butte 500 kV line contribute to the reliability of the Northwest AC Intertie (NWACI); outages to these lines could result in a restriction on the path limit to move resources from the northwest to California.

PGE has 15% ownership in the Colstrip-Townsend #1 and #2 500kV lines. These 500 kV lines are part of the Colstrip Transmission System (CTS) that moves resources from Montana to the Northwest.

The Bethel-Round Butte 230 kV line is part of the West of Cascades South (WOCS) Path. WOCS is a WECC Major Path and experiences heavy east-to-west flows in the winter, with generation resources on the east side of the Cascades serving the Willamette Valley.

The Horizon-St Marys-Trojan 230 kV and Harborton-Trojan #1 230 kV lines are part of the South of Allston (SOA) Path. The SOA Path experiences heavy north-to-south flows in the summer, with generation resources in the I-5 Corridor and Canada serving the Willamette Valley. For off-peak conditions in the northwest, these flows can reverse, serving the northwest from the south (southern Oregon or California) instead of the north. Both conditions can stress PGE's Transmission System; a Remedial Action Scheme (RAS) is in place to address north-to-south conditions. This RAS drops generation in the I-5 Corridor (including PGE's Port Westward 2 and Beaver plants) to mitigate overloads on the underlying 230 kV and 115 kV system and is triggered for the loss of the Allston BPA-Keeler BPA 500 kV or Keeler BPA-Pearl BPA 500 kV lines.

In total, PGE owns 1,630 circuit miles of sub-transmission/transmission at voltages ranging from 57 kV to 500 kV (See Figure 3).

Figure 3: PGE Circuit Miles Owned (By Voltage Level)

Voltage Level	Pole Miles	Circuit Miles
500 kV	268	268
230 kV	285	329
115 kV	531	570
57 kV	429	463

3.2. Load Forecast

For load forecasting purposes, PGE's transmission system is evaluated for a 1-in-3 peak load condition during the summer and winter seasons for Near Term (years 1 through 5) and Longer Term (years 6 through 10) studies.

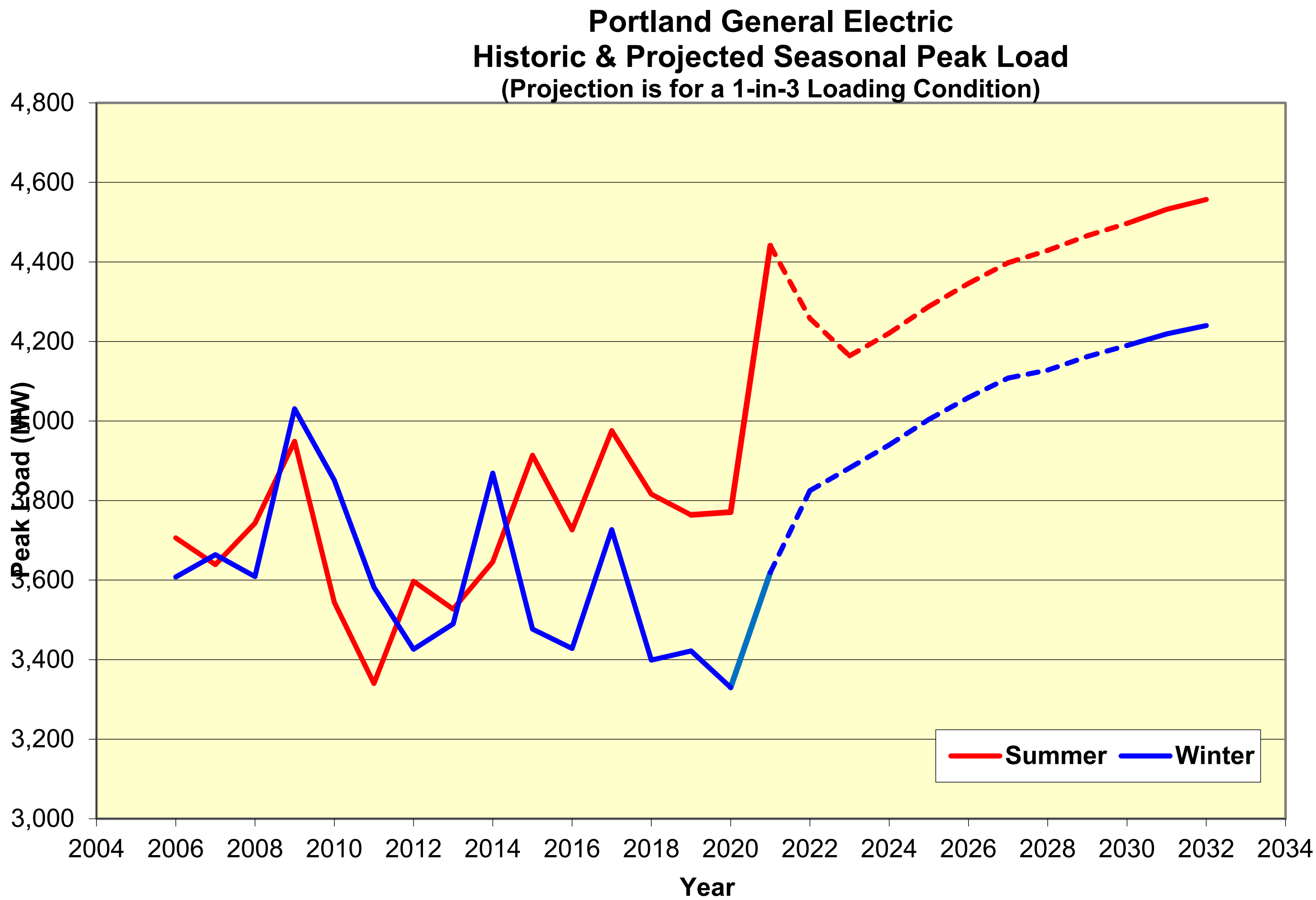
The 1-in-3 peak system load is calculated based on weather conditions that PGE can anticipate experiencing once every three years. The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high power transfers over PGE's T&D System to its customers. PGE defines the seasons to align with the seasons set by the Reliability Coordinator's seasonal planning process.

Figure 4: Summer/Winter Loading Conditions and Corresponding Daily-Averaged Temperatures

Summer	
1-in-2	83.1°F
1-in-3	85.1°F
1-in-5	87°F
1-in-10	89.1°F
1-in-20	90.9°F

Winter	
1-in-2	28.7°F
1-in-3	26.8°F
1-in-5	25.1°F
1-in-10	23.2°F
1-in-20	21.6°F

Figure 5: Portland General Electric's Historic & Projected Seasonal Peak Load
(Projection is for a 1-in-3 Loading Condition)



PGE's all-time peak winter load occurred on December 21, 1998, with the Net System Load[1] reaching 4073 MW. PGE's all time summer peak occurred on June 28, 2021 with the Net System Load reaching 4441 MW.

3.3. Forecasted Resources

The forecasted resources are comprised of generators, identified by network customers as designated network resources, that are integrated into the wider regional forecasts of expected resources committed to meet seasonal peak loads.

[1] The Net System Load is the total load served by PGEM, including losses. This includes PGE load in all control areas, plus ESS load, minus net borderlines.

3.4. Economic Studies

Eligible customers or stakeholders may submit economic congestion study requests during either Quarter 1 or Quarter 5 of the planning cycle. However, PGE did not receive any study requests during the 2022-2023 planning cycle.

3.5 Stakeholder Submissions

Any stakeholder may submit data to be evaluated as part of the preparation of the draft Near Term Local Transmission Plan and/or the development of sensitivity analyses, including alternative solutions to the identified needs set out in prior Local Transmission Plans, Public Policy Considerations and Requirements, and transmission needs driven by Public Policy Considerations and Requirements. However, PGE did not receive any such data submissions during the 2022-2023 planning cycle.

4. Methodology

PGE's transmission system is designed to reliably supply projected customer demands and projected Firm Transmission Services over the range of forecast system demands. Studies are performed annually to evaluate where transmission upgrades may be needed to meet the performance requirements established in the NERC TPL-001-4 Reliability Standard and the WECC TPL-001-WECC-CRT-3.1 Regional Criteria.

PGE maintains system models within its planning area for performing the studies required to complete the System Assessment. These models use data that is provided in WECC Base Cases in accordance with the MOD-032 reliability standard. Electrical facilities modeled in the cases have established normal and emergency ratings, as defined in PGE's Facility Ratings Methodology document. A facility rating is determined based on the most limiting component in a given transmission path, in accordance with the FAC-008-5 reliability standard.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 115 kV transmission system (primarily auto mode - time-clock; one auto mode - voltage control) and on the 57 kV transmission system (auto mode - voltage control).

Studies are evaluated for the Near Term Planning Horizon (years 1 through 5) and the Longer Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's transmission system. The load model used in the studies is based on PGE's corporate forecast, reflecting a 1-in-3 demand level for peak summer and peak winter conditions with additions of large customer loads. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. Particularly sensitive outages of varying duration may be studied per TPL-001-5, an upcoming version of the current standard TPL-001-4. Transmission equipment is studied as out of service in Base Case system models if there is no spare equipment or mitigation strategy for the loss of the equipment.

In the Near Term, studies are performed for the following:

- System Peak Load for either Year One or Year Two
- System Peak Load for Year Five
- System Off-Peak Load for either Year One or Year Two
- System Off-Peak Load for Year Five

Sensitivity studies are performed for each of these cases by varying the study parameters to stress the system within a range of credible conditions that demonstrate a measurable change in performance. PGE alters the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak summer and winter sensitivity cases, the 1-in-10 load forecast is used.

Studies are evaluated at peak summer and peak winter load conditions for one of the years in the Longer Term Planning Horizon.

Figure 6: Powerflow Base Cases Used in 2022 Assessment

		Study Year	Origin WECC Base Case	PGE Case Name	PGE System Load (MW)
SUMMER	Year One/Two Case	2024	2022 HS3	24 HS PLANNING	4735
	Year Five Case	2027	2027 HS2	27 HS PLANNING	5157
	Year One/Two Sensitivity	2024	2022 HS3	24 HS SENSITIVITY	5104
	Year Five Sensitivity	2027	2027 HS2	27 HS SENSITIVITY	5685
	Long Term Case	2032	2032 HS1	32 HS PLANNING	5554
WINTER	Year One/Two Case	2024-25	2022-23 HW2	24-25 HW PLANNING	4563
	Year Five Case	2027-28	2026-27 HW2	27-28 HW PLANNING	4841
	Year One/Two Sensitivity	2024-25	2022-23 HW2	24-25 HW SENSITIVITY	5022
	Year Five Sensitivity	2027-28	2026-27 HW2	27-28 HW SENSITIVITY	5505
	Long Term Case	2032-33	2031-32 HW1	32-33 HW PLANNING	5296
SPRING	Year One/Two Off Peak Case	2024	2022 LSP1	24 LSP PLANNING	2696
	Year Five Off Peak Case	2027	2027 HS2	27 LSP PLANNING	3147
	Year One/Two Off Peak Sensitivity	2024	2022 LSP1	24 LSP SENSITIVITY	2696
	Year Five Off Peak Sensitivity	2027	2027 HS2	27 LSP SENSITIVITY	3147

The Bulk Electric System is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-4 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-4 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

4.1. Steady State Studies

PGE performs steady-state studies for the Near-Term and Long-Term Transmission Planning Horizons. The studies consider all contingency scenarios identified in Table 1 of the NERC TPL-001-4 reliability standard to determine if the Transmission System meets performance requirements. These studies also assess the impact of Extreme Events on the system expected to produce severe system impacts.

The contingency analyses simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to voltage limitations and tripping of transmission elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Capacity addition projects are developed when simulations indicate the system's inability to meet the steady-state performance requirements for P0 (System Normal) or P1 events. For P2-P7 events, PGE identifies mitigations, including system topology changes (circuit breaker switching), moving selective transfer substations to alternate feeds, re-dispatching generation, and the implementation of committed transmission system upgrades, in order to eliminate identified overloads. Load shedding is also considered as on option to eliminate identified transmission overloads, but only as a last resort.

4.2. Voltage Stability Studies

PGE's transmission system is evaluated for voltage stability in accordance with the WECC established procedures and criteria[2]. These performance criteria are summarized in the table below. Contingencies to PGE and adjacent utility equipment at 500 kV and 230 kV are evaluated.

[2] "Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power," prepared by the Reactive Reserve Working Group (RRWG) and approved by the Technical Studies Subcommittee (TSS) on March 30, 2006. https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Voltage%20Stability%20Guide.pdf&action=default&DefaultItemOpen=1

Figure 7. Voltage Stability Performance Criteria

WECC Performance Level	TPL-001-4 Category	Disturbance	MW Margin (PV Method)	MVAR Margin (QV Method)
A	P0	No Contingency	≥ 5%	Positive Reactive Power Margin
B	P1[3]	A Single Element	≥ 5%	Positive Reactive Power Margin
C	P2-P7[4]	Any Two Elements	≥ 2.5%	Positive Reactive Power Margin
D	N/A	Extreme Events	> 0	Positive Reactive Power Margin

For PGE's Real Power Margin assessment, the "transfer path" studied is identified by the Northwest (Area 40) generation as the (source) and PGE generation and load as the sink. Load internal to PGE's local transmission system is scaled up to increase the "path" flow until a voltage stability limit is identified.

4.3 Transient Stability Studies

PGE evaluates the voltage and transient stability performance of the Transmission System for contingencies to PGE and adjacent utility equipment at 500 kV, 230 kV, and 115 kV. The studies evaluate single line-to-ground and 3φ faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit transmission line. Extreme events are studied for 3φ faults with Delayed Fault Clearing.

For all 500 kV and 230 kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the protection system operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500 kV and 230 kV facilities; and the majority of 115 kV facilities. Delayed clearing occurs when a breaker fails to operate and the breaker-failure scheme clears the fault. Facilities without delayed clearing are modeled as such in the contingency definition.

The transient stability results are evaluated for compliance with the following NERC and WECC system performance requirements. The simulation durations are run to 20 seconds. All oscillations that do not show positive damping within 20 seconds after the start of the studied event shall be deemed unstable.

1. Rotor Angle Stability
   Generators must maintain synchronism with PGE's transmission system and the rest of the transmission system in the Northwest through the transient period and rotor angle oscillations must exhibit positive damping for the loss of either one or two system elements.

[3] Not all NERC TPL-001-4 Categorical outages are specifically identified in the WECC Performance Criteria.
[4] TPL-001-4 P6 is not included in the WECC Performance Criteria.

2. Frequency Stability
   System frequency at any load bus must not fall below:

   - 59.6 Hz for 6 cycles or more following the loss of a single system element.
   - 59.0 Hz for 6 cycles or more following the loss of two system elements.

3. Voltage Stability

   Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.

   Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds, for all P1 through P7 events.

   For Contingencies without a fault (P2-1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.

Failure to meet the above performance requirements for any transient stability simulation will necessitate some form of mitigation.

Contingency analyses simulate the removal of all elements that the Protection System and other automatic controls expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized
- Tripping of generators due to voltage limitations
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models

Automatic controls simulated include generator exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Corrective Action Plans are developed if the stability studies indicate that the system cannot meet the TPL-001-4 and WECC performance requirements.

- P1: No generating unit pulls out of synchronism

- P2-P7: When a generator pulls out of synchronism, the resulting apparent impedance swings do not result in the tripping of any Transmission system elements other than the generating unit and its directly connected facilities
- P1-P7: Power oscillations exhibit acceptable damping

5. Results

5.1. Steady State Results – Near Term Evaluation

The majority of the contingency loading concerns identified on PGE's system for the Near Term Planning Horizon are mitigated by implementing BPA's DSO 309, addressing the South of Allston Path RAS. However, increased load in the Near Term Planning Horizon has caused a number of new overloads to appear as well as push existing contingencies that were previously being monitored, to worsen.

The majority of new overloads seen in the 2022 TPL results are driven by large increases in projected loads across the system – prompting new facilities and upgrading existing facilities as more load requests come in. These load requests across the region have increased the general number the projects identified in the 2022 TPL results, compared to previous years.

The following lines are being planned for reconductoring and/or new construction to address future overloads found in the Near Term TPL cases:

- Shute-Sunset #1 115 kV
- Horizon-Keeler BPA #1 230 kV
- Murrayhill-Sherwood #1 230 kV
- Murrayhill-Sherwood #2 230 kV
- Murrayhill-St Marys #2 230 kV
- Hogan South – McGill 115 kV
- Pearl/Sherwood reinforcement project (Pearl BPA-Sherwood 230kV and McLoughlin-Pearl BPA-Sherwood 230 kV)

Several BPA projects have also been identified as critical to meeting load increases within PGE service territory. These include:

- Rivergate-Ross BPA 230kV
- Keeler 230kV bus sectionalizing breaker
- A second Keeler 500/230kV transformer

There are no additional contingency loading or voltage concerns in the Near Term Planning Horizon on PGE's system for NERC TPL-001-4 Categories P1, P2, P3, P4, P5, and P7. NERC TPL-001-4 Category P6 contingency overloads and voltage concerns are addressed with load shedding, as permitted, on PGE's local distribution system. None of the contingencies evaluated will result in cascading from PGE's Control Area to another Control Area.

5.2. Near Term Voltage Stability

There are no voltage stability concerns identified on PGE's system in the Near Term Planning Horizon.

5.3. Near Term Transient Stability

The Near Term transient stability studies indicate that PGE's system exhibits adequate transient stability throughout the 500 kV and 230 kV transmission systems. The minimum frequency response recorded did not dip below 59.5 Hz for any of the contingency events studied on PGE's system. Underfrequency Load Shedding ("UFLS") relays are not affected because the set point for UFLS relays is 59.3 Hz. Simulations have identified the possibility of voltage dips on several 115 kV load buses for a multiple-element outage related to the McLoughlin 230 kV substation. These voltage dips would result in loss of load at three local 115kV substations; however, no malignant impacts to the 230kV system, nor any cascading outages at adjacent substations, have been observed.

5.4. Near Term Short Circuit Analysis

The Near Term short circuit analysis identified two overdutied breakers:

- Sherwood circuit breaker V274
- Sunset circuit breaker W196

Both breakers are scheduled for replacement.

5.5. Projects Currently Included in the Near Term Plan

There are 18 projects currently planned for implementation in the Near Term Planning Horizon. The timing for completion of these projects is subject to change. These projects are described in detail in Appendix A.

Appendix A: Near Term Project List

Projects currently included in the Near Term Plan are:

- Harborton Reliability Project
- Horizon-Keeler BPA #2 230 kV Project
- Reedville Substation Rebuild
- Memorial Substation Project
- Tonquin Substation Project
- Kaster Substation Project
- Redland Substation Project
- Scholls Ferry Substation Project
- Pearl BPA-Sherwood 230 kV Project
- Groveland Substation Project
- Glencullen Rebuild & Cedar Hills Breakers
- Willamette Valley Resiliency Project (4 parts)
- SE Portland Conversion Project – Holgate Substation Conversion
- Hillsboro Reliability Project
- Mt Pleasant Substation Project
- Horizon-Keeler BPA #1 230 kV Reconductor
- Murrayhill-St Marys #2 230 kV
- Murrayhill-Sherwood #1 and #2 230 kV Reconductor

These projects are described in more detail on the following pages.

Harborton Reliability Project

- **Project Purpose**
  - Address transmission operations flexibility for the loss of the Rivergate bulk power transformer.
  - Reconfigure the system to reduce exposure and provide a stronger source to the Northwest Portland 115 kV system.
- **Project Scope**
  - Rebuild the Harborton 115 kV yard to a breaker and one half configuration.
  - Build a new 230 kV breaker and one half yard at Harborton substation.
  - Route five 230 kV lines to Harborton.
  - Install a new bulk power transformer at Harborton.
  - Reconductor the 115 kV lines from Harborton to Canyon.
  - Reconfigure the 115 kV system to provide a source to Northwest Portland from Harborton substation.
- **Project Status**
  - Under Construction.
- **Project Requirement Date**
  - The initial Phase 1 of this project includes the 115 kV yard rebuild, the Harborton-Rivergate 115 kV circuit and Harborton-St Helens 115 kV circuit. This phase was completed in April 2020.
  - The remaining Phase 1 of this project includes the 230 kV yard, the Harborton-Rivergate 230 kV circuit, the Harborton-Trojan #1 230 kV circuit and the new bulk power transformer. This phase is scheduled for completion by Q2 2021.
  - Phase 2 of this project first reconductors the E-Wacker 115 kV line to 1272 ACSS. Next, the 115 kV system is reconfigured to create a Harborton-Wacker 115 kV circuit, which will also be reconductored to 1272 ACSS. The 115 kV line idled for this reconfiguration will be utilized for the fifth 230 kV source into Harborton. The Horizon-St Marys-Trojan 230 kV circuit will be looped into Harborton, creating the Harborton-Horizon 230 kV, Harborton-St Marys 230 kV, and Harborton-Trojan #2 230 kV circuits. This phase is scheduled to begin after the Canyon-Urban 115 kV Reconductor and is scheduled for completion by Q3 2026.

Horizon-Keeler BPA #2 230 kV Project

- **Project Purpose**
  - Significant load growth in the Hillsboro area has accelerated the need for another 230 kV source in the Near Term Planning Horizon. Studies indicate that the loss of the Keeler BPA-St Marys 230 kV line can cause the Horizon-Keeler BPA 230 kV line to approach its thermal rating during peak summer conditions. Conversely, the loss of the Horizon-Keeler BPA 230 kV line can cause the Keeler BPA-St Marys 230 kV line to approach its thermal rating during peak summer conditions. The loss of both the Horizon-Keeler BPA 230 kV line and the Horizon-St Marys-Trojan 230 kV line results in significant overloads on the underlying 115 kV system that can occur during all loading conditions.
- **Project Scope**
  - Construct a Horizon-Keeler BPA #2 230 kV line with 2156 ACSS conductor. A new bay will be installed on the east 230 kV bus at BPA's Keeler substation to accommodate the new line position. At Horizon substation, the remainder of the bay installed for the Horizon VWR3 transformer will be constructed. The existing lines at Horizon will both move one bay west, and the new line will terminate in the east-most bay.
- **Project Status**
  - Design Complete. Construction Sequencing in progress.
- **Project Requirement Date**
  - Project projected for completion Q2 2024.

Reedville Substation Rebuild

- **Project Purpose**
    - Address antiquated equipment and improve resiliency at the Reedville substation following an extended unplanned outage.
- **Project Scope**
    - Rebuild the Reedville substation to a 115 kV GIS ring bus configuration with three 115 kV lines and three 50 MVA distribution transformers. Construct a new Reedville-St Marys 115 kV line using the existing St Marys-Huber 115 kV line and part of the existing Murrayhill-Reedville 115 kV line. Construct a new 795 ACSS line section to create a new Murrayhill-Reedville 115 kV line.
- **Project Status**
    - Design Complete. Acquiring permits and materials.
- **Project Requirement Date**
    - Project projected for completion Q3 2024.

Memorial Substation Project

- **Project Purpose**
  - Address load growth in the Wilsonville region from multiple different customers, including new water treatment facilities.
- **Project Scope**
  - Construct a new 4-position ring bus 115 kV substation with two 115 kV line and two distribution transformer positions (one to be installed initially).
  - Loop the existing Sherwood-Wilsonville 115 kV circuit into the substation, creating an Memorial-Sherwood 115 kV line and an Memorial-Wilsonville 115 kV line.
- **Project Status**
  - Design Complete. Construction Sequencing in progress.
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2024.

Tonquin Substation Project

- **Project Purpose**
    - Address upcoming load growth, including new water treatment facilities.
    - Address loading concerns on the Oswego-West Portland 115 kV line.
- **Project Scope**
    - Construct a new 115 kV, 5-position ring bus with three 115 kV line and two distribution transformer positions (one transformer position will be for future use).
    - Loop the existing Meridian-Sherwood 115 kV circuit into the substation, creating a Meridian-Tonquin 115 kV line and a Sherwood-Tonquin 115 kV line.
    - Reconfigure the McLoughlin-Wilsonville 115 kV circuit and install a new breaker position at Rosemont substation, creating the McLoughlin-Tonquin 115 kV circuit and the Rosemont-Wilsonville 115 kV circuit.
- **Project Status**
    - Design Complete. Construction Sequencing in progress.
- **Project Requirement Date**
    - Phase 1 of this project will build out the substation, loop in the Meridian-Sherwood 115 kV circuit, and install two distribution transformers. This phase is scheduled for completion by Q4 2023.
    - Phase 2 of this project will reconfigure the McLoughlin-Wilsonville 115 kV circuit and install a new breaker position at Rosemont substation, creating the McLoughlin-Tonquin 115 kV circuit and the Rosemont-Wilsonville 115 kV circuit. This phase is scheduled for completion by Q4 2024.

Kaster Substation Project

- **Project Purpose**
  - Load growth in the St Helens area dictates the need to construct a new substation for distribution capacity. The new substation will also serve the existing Cascade substation load, which will enable the decommissioning of the antiquated Cascade substation.
- **Project Scope**
  - Construct a new 115 kV, 6-position ring bus substation with two 115 kV lines, two distribution transformers, and a 115 kV cap bank. Disconnect the Harborton-St Helens 115 kV line from St Helens and route the line to the new Kaster substation, creating the Harborton-Kaster 115 kV line. Reconductor the existing St Helens-Cascade 115 kV line to 795 ACSS, disconnect the line from the Cascade substation, and terminate the line at the Kaster substation, creating the Kaster-St Helens 115 kV line
- **Project Status**
  - Awaiting City of St Helens land use decision
- **Project Requirement Date**
  - The project schedule is dependent on land availability. It will require minimum 3 years from the time of any land procurement.

Redland Substation Project

- **Project Purpose**
  - Load in the Redland and Leland areas has increased, resulting in the Redland substation becoming heavily loaded and in need of additional capacity. Additionally, Redland substation has many assets aged past their useful life span including antiquated communication systems, necessitating the need for a substation rebuild.
- **Project Scope**
  - Completely rebuild Redland substation with two 28 MVA transformers.
- **Project Status**
  - Being scoped for construction
- **Project Requirement Date**
  - The project is currently scheduled for completion by June 2025

Scholls Ferry Substation Project

- **Project Purpose**
    - Address increased load in the Scholls Ferry region with an updated substation, converted to a 4 position ring bus, and a new additional distribution transformer.
- **Project Scope**
    - Construct a 4-position ring bus at Scholls Ferry 115 kV substation
    - Add an additional 50 MVA distribution transformer to the newly created position
- **Project Status**
    - Awaiting funding approval
- **Project Requirement Date**
    - The project is currently projected for completion by Q4 2025.

Pearl/Sherwood 230 kV Reinforcement Project

- **Project Purpose**
  - Mitigate the overloading of the McLoughlin-Pearl BPA-Sherwood 230 kV line caused by the P1-2 contingent loss of the Pearl BPA-Sherwood 230 kV line.
- **Project Scope**
  - Bifurcate the Pearl BPA-Sherwood 230 kV line into Pearl BPA-Sherwood #1 and #2 230 kV lines.
  - Bifurcate the McLoughlin-Pearl BPA-Sherwood 230 kV line into the Pearl BPA-Sherwood #3 and McLoughlin-Pearl BPA-Sherwood 230 kV lines.
  - Reconductor Pearl BPA-Sherwood #3 and the Pearl BPA to Sherwood sections of the McLoughlin-Pearl BPA-Sherwood 230 kV line with 2165 ACSS.
- **Project Status**
  - Initial scoping and ongoing coordination with BPA.
- **Project Requirement Date**
  - Q2 2026

Groveland Substation Project

- **Project Purpose**
  - Address new customer load with full N-1 distribution transformer redundancy.
- **Project Scope**
  - Construct a new 115 kV breaker-and-a-half substation with three 115 kV line and two distribution transformer positions.
  - Loop the Helvetia-West Union 115 kV circuit into the substation, creating a Groveland-Helvetia 115 kV line and a Groveland-West Union 115 kV line.
  - Relocate the spare 115/57 kV transformer to Groveland and purchase a new spare.
  - Rebuild the existing Banks-Orenco 57 kV line between Groveland and Orenco to 115 kV, creating the Groveland-Orenco 115 kV circuit.
  - Terminate the Banks-Orenco 57 kV line at Groveland, creating the Banks-Groveland 57 kV circuit.
- **Project Status**
  - Initial scoping
- **Project Requirement Date**
  - Phase 1 of this project will build out the substation, loop in the Helvetia-West Union 115 kV circuit, and install two distribution transformers. This phase is scheduled for completion by Q2 2025.
  - Phase 2 of this project will re-terminate the Orenco end of the Banks-Orenco 57 kV line at Groveland, install a 115/57 kV transformer at Groveland, and rebuild the idled 57 kV line to create the Groveland-Orenco 115 kV circuit. This phase schedule is still being determined.

Glencullen Rebuild & Cedar Hills Breakers

- **Project Purpose**
  - Excessive outage durations to perform planned and unplanned maintenance drove a need to reconfigure Glencullen substation as well as upgrade nearby the Cedar Hills substation breakers. This project also reduces some overloads seen on the surrounding 115 kV system during certain P6 events. This project also helps improve reliability to critical infrastructure, such as St. Vincent Hospital, by converting the substation from a selective transfer station, to a breaker station.
- **Project Scope**
  - Construct a 5-position ring bus at Glencullen with three 115 kV sources
  - Upgrade existing Circuit Switchers at Cedar Hills to Circuit Breakers.
- **Project Status**
  - Initial scoping
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2026.

Willamette Valley Resiliency Project – Monitor 115 and 230 kV Substation Project

- **Project Purpose**
  - Part of the Willamette Valley Resilience Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. Monitor is being converted from a 57/230 kV simple substation, to a 57/115/230 kV Ring Bus substation.
- **Project Scope**
  - Construct 115 and 230 kV Ring Bus for Monitor Substation. In the long term planning horizon, five 57 kV substations in the central region of PGEs service territory will be converted to 115 kV, with additional upgrades to existing 115 kV and 230 kV substations such as Bethel and Monitor.
  - Monitor 115 kV will be built to a 5 position ring bus with two transformers (57/115 kV and 115/230 kV).
  - Monitor 115 kV will also include a capacitor bank.
  - Monitor 230 kV will be built as a 4 position ring bus
- **Project Status**
  - Approved project with funding. Construction will be done in phases over an 8 year period with Monitor being the first portion of the work to be completed in an estimated 3 years.
- **Project Requirement Date**
  - Construction to be done in phases over an 8 year period. Monitor 115 and 230 kV substation expected to be complete in Q4 2025. Rebuilt substations will be energized at 57kV until Q4 2028, when all WVRP substation are re-energized at 115kV.

Willamette Valley Resiliency Project – St Louis 115 kV Project

- **Project Purpose**
    - Part of the Willamette Valley Resilience Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. St Louis substation is being converted from a 57 kV simple substation, to a 115 kV ring bus.
- **Project Scope**
    - Construct 4 position 115 kV Ring Bus St Louis substation.
    - Two distribution 28.0 MVA transformers to be included.
    - Two 115 kV sources
        - Waconda-St Louis
        - North Marion-St Loius
- **Project Status**
    - Approved project with funding. Construction will be done in phases over an 8 year period with St Louis being the first portion of the work to be completed in an estimated 3 years.
- **Project Requirement Date**
    - Construction to be done in phases over an 8 year period. St Louis substation expected to be complete in Q4 2025. Rebuilt substation will be energized at 57kV until Q4 2028, when all WVRP substations are re-energized at 115kV.

Willamette Valley Resiliency Project – North Marion 115 kV Project

- **Project Purpose**
  - Part of the Willamette Valley Resilience Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. North Marion substation is being converted from a 57 kV substation, to a 115 kV ring bus.
- **Project Scope**
  - Construct 6 position 115 kV Ring Bus North Marion substation.
  - Two distribution 28.0 MVA transformers to be included.
  - Three 115 kV Transmission Sources
    - North Marion-Twilight
    - North Marion-St Louis
    - North Marion-Woodburn
- **Project Status**
  - Approved project with funding. Construction will be done in phases over an 8 year period with the North Marion portion of the work to be completed in an estimated 5 years.
- **Project Requirement Date**
  - Construction to be done in phases over an 8 year period. North Marion 115 kV substation expected to be complete in Q4 2027. Rebuilt substation will be energized at 57kV until Q4 2028, when all WVRP substations are re-energized at 115kV.

Willamette Valley Resiliency Project – Woodburn 115 kV Project

- **Project Purpose**
  - Part of the Willamette Valley Resilience Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. Woodburn substation is being converted from a 57 kV substation, to a 115 kV ring bus.
- **Project Scope**
  - Construct a 4-position 115 kV Ring Bus Woodburn substation.
  - Two distribution 28.0 MVA transformers to be included.
  - Two 115 kV Sources
    - North Marion-Woodburn
    - Monitor-Woodburn
- **Project Status**
  - Approved project with funding. Construction will be done in phases over an 8 year period with the Woodburn portion of the work to be completed in an estimated 5 years.
- **Project Requirement Date**
  - Construction to be done in phases over an 8 year period. Woodburn 115 kV substation expected to be complete in Q4 2027. Rebuilt substation will be energized at 57kV until Q4 2028, when all substations are re-energized at 115kV.

SE Portland Conversion Project – Holgate Substation Conversions

- **Project Purpose**
    - The SE Portland Conversion Project addresses antiquated equipment and resiliency in the SE Portland area. The project will be completed in multiple phases; the Holgate Substation Conversion is scheduled for completion in the Near Term Planning Horizon.
- **Project Scope**
    - The Holgate substation will be rebuilt to a 115 kV breaker station. The Gresham-Harrison PACW 115 kV line will be looped into the substation, creating the Gresham-Holgate 115 kV line and the Harrison PACW-Holgate 115 kV line. The existing distribution transformers will be replaced with two 28 MVA transformers and two metalclad switchgear will be installed.
- **Project Status**
    - Design in progress.
- **Project Requirement Date**
    - This project is projected for completion in Q2 2026.

Hillsboro Reliability Project

- **Project Purpose**

The Hillsboro Reliability Project constructs additional bulk power transformer capacity to serve the North Hillsboro area. In addition, the conversion of Brookwood substation and Main substation provides loading relief to the Hillsboro area 57 kV System while providing additional distribution transformer capacity. The Orenco substation rebuild provides improved reliability and additional distribution capacity, as well as mitigates breakers at Orenco that will become overdutied upon the energization of Evergreen substation.

- **Project Scope**

The new Evergreen bulk power substation will be constructed in Q2 2024. The 230 kV yard will be two bays of breaker and one half, with two lines and two bulk power transformers. The Harborton-Horizon 230 kV line will be looped into Evergreen, creating the Evergreen-Harborton 230 kV and Evergreen-Horizon 230 kV lines. The 115 kV yard will also be breaker and one half with five 115 kV line positions and two bulk power transformer positions. Two 115 kV cap banks will be installed for voltage support. The Helvetia-Shute 115 kV line will be looped into Evergreen, creating the Evergreen-Helvetia 115 kV and Evergreen-Shute 115 kV lines. The Rock Creek-Shute-Sunset 115 kV line will be unbundled to create the Evergreen-Rock Creek 115 kV line and the Evergreen-Sunset 115 kV line. The Evergreen-Shute 115 kV line will be reconductored to 1272 ACSS and a second Evergreen-Shute 115 kV line will also be constructed. Two 120/34.5 kV, 150 MVA distribution transformers will also be installed to serve new load growth in the area.

The Brookwood and Main substations will be converted to 115 kV with gas-insulated switchgear (GIS) ring bus configurations. Four new 115 kV lines will be constructed: Brookwood-Shute 115 kV, Brookwood-St Marys 115 kV, Brookwood-Main 115 kV, and Main-Roseway 115 kV. Both substations will have increased distribution capacity.

The Orenco substation 115 kV yard will be rebuilt to a breaker and one half configuration in 2023, using 63 kA breakers to mitigate fault duty concerns created by the energization of the Evergreen substation. The existing distribution yard will be eliminated, moving the distribution transformers to the main bus.

- **Project Status**
  - Project currently in various stages of design and construction.
- **Project Requirement Date**
  - The project is currently projected for complete completion by Q2 2027.

Mt Pleasant Substation Project

- **Project Purpose**
  - Upgrade Mt Pleasant 115 kV substation to a breaker station to address local load growth in the area.
- **Project Scope**
  - Upgrade Mt Pleasant 115 kV substation from a tapped manual switch substation off of the Canemah-McLoughlin 115 kV line to a breaker station with two sources:
    - Canemah-Mt Pleasant 115 kV
    - Carver-Mt Pleasant 115k V
  - Upgrade the existing 16.8 MVA transformer to a 28 MVA transformer.
- **Project Status**
  - Project in initial scoping phase
- **Project Requirement Date**
  - Q4 2027

Horizon-Keeler BPA #1 230 kV Reconductor

- **Project Purpose**
  - Mitigate overloads seen on the Horizon-Keeler BPA #1 230 kV line due to Hillsboro-area load growth.
- **Project Scope**
  - Reconductor the Horizon-Keeler BPA #1 230 kV line from 1272 ACSS to a larger conductor size.
- **Project Status**
  - Project in initial study phase.
- **Project Requirement Date**
  - Anticipated in-service date of Q2 2026

Murrayhill-Sherwood #1 and #2 230 kV Reconductor

- **Project Purpose**
  - Mitigate overloads caused by the loss of other 500 and 230kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. These flow conditions are the result of changing generation dispatch (increased solar from California), the addition of 500 and 230 kV infrastructure landing in the Sherwood area, and load growth within PGE service territory.
- **Project Scope**
  - Reconductor the Murrayhill-Sherwood #1 and #2 230 kV transmission lines from 1272 AAC to 2156 ACSS
  - Replace the remaining 230kV circuit breakers at Sherwood with higher fault duty equipment
- **Project Status**
  - Pre-scoping and initial study phase.
- **Project Requirement Date**
  - No firm date currently available. Targeting 2026.

Murrayhill-St Mary's #2

- **Project Purpose**
  - Mitigate overloads caused by the loss of other 500 and 230kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. These flow conditions are the result of changing generation dispatch (increased solar from California), the addition of 500 and 230 kV infrastructure landing in the Sherwood area, and load growth within PGE service territory.
- **Project Scope**
  - Construct a second Murrayhill-St Mary's 230 kV line using existing right of way.
  - Rebuild Murrayhill 230kV yard as a 3-bay, six position, breaker-and-a-half configuration
  - Rebuild Murrayhill 115kV as a GIS substation. Relocate the load service within the 115kV yard
- **Project Status**
  - Pre-scoping and initial study phase.
- **Project Requirement Date**
  - No firm date currently available. Targeting 2027.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Pricing and Tariffs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Robert Macfarlane
Christopher Pleasant

February 15, 2023

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 Exhibit 1200.

My name is Christopher Pleasant. I am a Senior Regulatory Analyst 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 changes recover PGE's 2024 revenue requirement in a way that achieves fair, just, and reasonable prices for our customers. In addition to estimating the overall effect on customer bills, our testimony also describes the revenue requirement allocation process (i.e., ratespread) and the rate design. We further:

1. Propose to eliminate the energy blocking associated with Schedule 7 residential customers;
2. Respond to Public Utility Commission of Oregon (Commission) Order No. 22-129 related to Decoupling;
3. Discuss updating PGE's Time-of-Day (TOD) rate and request that the Commission close PGE's Legacy Time-of-Use (TOU) rate to new enrollments;
4. Propose to clarify that energy storage used to integrate renewables on a utility's system qualifies as "associated energy storage" and should be included in Schedule 122, PGE's Renewable Resources Automatic Adjustment Clause (RAC);
5. Summarize the updates to Schedule 125;
6. Summarize the updates to Schedule 126;

7. Summarize the updates to prices contained in Schedule 300, Charges as Defined by the Rules and Regulations and Miscellaneous Charges;
8. Discuss concerns around expanding customer ownership of substations;
9. Discuss adjustments to the Rules and Regulations portion of the PGE Tariff; and
10. Introduce a new PGE Tariff, E-19.

Q. Please summarize the projected Cost of Service (COS) rate impacts resulting from the proposed allocations.

A. Table 1 below summarizes the base rate impacts for the major rate schedules and the overall COS and Direct Access (DA) impact. PGE Exhibit 1302 contains more detailed information on the rate impacts for the individual schedules. Table 1 of PGE Exhibit 1302 contains the base rate impacts of the proposed prices effective January 1, 2024. The detailed bill impacts starting on page 2 of PGE Exhibit 1302 relate to prices effective January 1, 2024, inclusive of the estimated changes in supplemental schedules known at this time.

Table 1
Estimated Cost of Service Base Rate Impacts Inclusive of Schedules 122, and 125, and 146.

Schedule	January 1, 2024
Schedule 7 Residential	15.7%
Schedule 32 Small Nonresidential	15.9%
Schedule 83 31-200 kW	12.5%
Schedule 85 201-4,000 kW	13.7%
Schedule 89 Over 4,000 kW	9.9%
Schedule 90 30 MWa	10.7%
COS & DA Overall	14.0%

II. UE 394 Stipulation-Generation Demand Charges

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

A. The purpose of this portion of our testimony is to discuss the ramping of generation demand charges for Schedules 83 and 85 as directed in the Fourth Partial Stipulation in PGE's last general rate case (GRC), Docket No. UE 394 (UE 394). In that stipulation, PGE agreed to address the timeline for the ramping of generation demand charges in our next GRC filing. The Commission approved the Fourth Partial Stipulation in Order No. 22-129.

Q. Please describe the rate design of generation demand charges that customers on Schedules 83 and 85 currently pay.

A. Nonresidential customers with demand between 31-200 kW are priced using Schedule 83 and those with demand between 201-4,000 kW are priced using Schedule 85. Currently, 25% of generation allocations for these two schedules receive the generation demand charge. Additionally, in 2023, transition adjustments for direct access opt-outs on Schedules 483 and 485 are calculated as the difference between generation cost-of-service *volumetric* charges and market value (as is done now in the absence of a generation demand charge). The generation demand charge is applied directly to Schedule 483 and 485 customers during the transition adjustment period. For long-term opt outs, updates to fixed generation costs that are charged volumetrically, such as Schedule 122 RAC updates, will apply to the transition adjustment. Changes to fixed generation costs charged via the generation demand charge will apply directly to the demand charge. Future increases in the generation demand charge that are simply the result of rate redesign (i.e., moving recovery of fixed generation costs from the volumetric charge to the demand charge) will be accompanied by a recalculation of the transition adjustment using the reduced volumetric charge.

Q. How does PGE propose to set the Generation Demand Charges for Schedules 83 and 85 in this proceeding?

A. For both Schedules 83 and 85, fixed generation represents approximately 42% of total generation costs. Since PGE currently only collects 25% of generation in the demand charge, PGE proposes to increase the generation demand charges for Schedule 83 and 85 to 35% of total generation. This increase will better align fixed generation cost recovery via the generation demand charge while allowing for continued gradual changes of future generation demand charges.

Q. Why would PGE not set the generation demand charge to recover all fixed generation costs for Schedules 83 and 85?

A. Fixed generation is currently defined as generation revenue requirement other than net variable power costs. Given the relatively recent experience of demand changes for these customers, we prefer to use gradualism to increase the generation demand charge over time towards the allocated full fixed cost revenue requirement.

III. Ratespread

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 (separately, Metering, Billing, and Other Consumer Services) functional revenue requirements in the rate-spread process. The marginal cost of service study is presented in PGE Exhibit 1201.

Q. How do you calculate and allocate the 2024 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[1] by the projected 2024 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 (4CP) 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 2019 Integrated Resource Plan. Additionally, PGE's highest annual peak load hours generally occur during one of these four months.

[1] *See* PGE Exhibit 1200.

Q. What are the respective capacity and energy percentages used in allocating the generation revenue requirements?

A. Capacity comprises approximately 30.2% of the marginal cost of generation and energy approximately 69.8%. These figures reflect the inclusion of load following costs as a capacity cost. The corresponding figures from UE 394 were approximately 31.0% and 69.0%.

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 (12CP) multiplied by the unit marginal transmission costs presented in PGE Exhibit 1201. This methodology is consistent with PGE's last GRC, UE 394, 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 unbundling 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 investment 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 energy and capacity bases. 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 the basis of energy. 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 1304.

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 394, 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 through the Customer Impact Offset (CIO). We do this for these 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, subtransmission, 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 one customer with six accounts engaging in similar activity, there is virtually no 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. PGE is proposing to remove the block energy rate differential for all residential customers.

Schedule 32, Small Nonresidential 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 Nonresidential Standard Service (31 kW to 200 kW), applies to all secondary voltage Large Nonresidential 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 charges, there is a Transmission Demand Charge based on the highest metered kW reading for a 30-minute period during on-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 Nonresidential 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 Nonresidential 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 on-peak intervals. These on-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 Charges will continue to be on- and off-peak differentiated.

Schedule 90, Large Nonresidential (>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 propose to continue the load following/integration credit for Schedule 90?

A. Yes. We propose to continue this concept, applicable to 360 MWa based on expected average load, and to incorporate the credit amount of approximately $5.6 million into the base energy charges for Schedule 90 customers. In addition, it would only apply to customers with aggregate load over 250 MWa portion. This $5.6 million is allocated to other COS customers and recovered through their respective energy charges.

Q. Please provide additional context for the proposed changes to Schedule 90.

A. PGE began an evolution of our cost of service rate classes for nonresidential customers 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 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[2] 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; and
- 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 1303, 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:

Table 2
Schedule 7 - Residential Service Proposed Prices

Category	Prices
Basic Charge – Multifamily	**$10.00 per customer per month**
Basic Charge – Single Family	**$13.00 per customer per month**
Transmission & Related Service Charge	**7.85 mills per kWh**
Distribution Charge	**69.78 mills per kWh**
Energy Charge	**81.61 mills per kWh**

[2] Principles of Public Utility Rates, by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, 2nd Edition, 1988.

Q. Please explain how you develop these prices.

A. We split the Basic Charge and have 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 each from the current $11 to $13 monthly amount for single-family and from the current $8 to $10 monthly amount for multi-family. When the current Basic Charge was established in UE 394, it made up 9% of a customer's bill. Without updating, PGE would recover only 8% of the bill via the Basic Charge. PGE's proposal to increase the Basic Charge by $2 for residential customers will allow PGE to recover 9% of a customer's bill via the Basic Charge. 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 mitigate a Basic Charge increase for low-income customers enrolled in the program, which is expected to reach 95,000 customers by the end of 2023.

We develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

We calculate the **Distribution Charge** of 69.78 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. What structural change is proposed for Schedule 7?

A. We propose to continue implementation from our proposal in UE 394 and completely eliminate the energy charge blocking differential structure of under/over 1,000 kWh for residential customers. In UE 394 we reduced the blocking differential by half the price differential to begin to remove the blocking in the energy charge.

Q. Why do you propose to remove the Schedule 7 energy charge blocking?

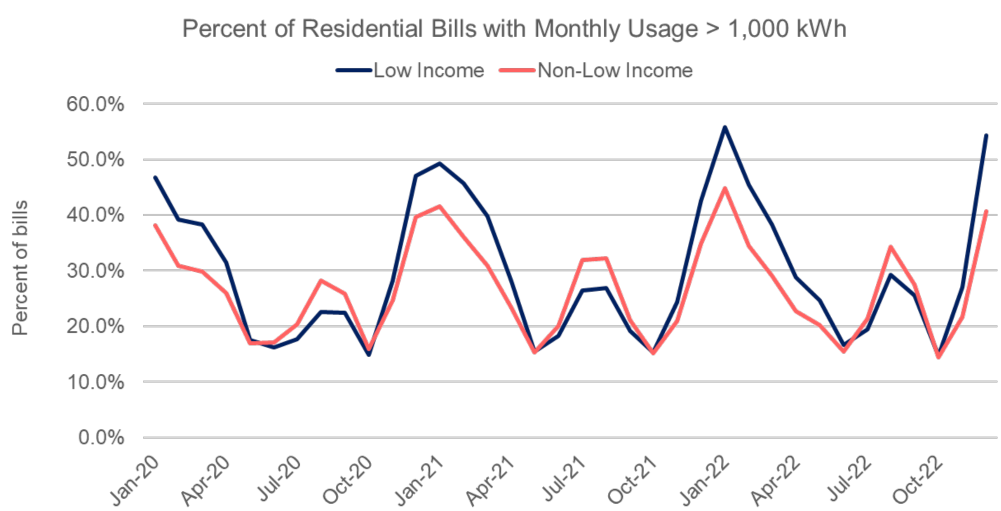
A. The initial goals of energy charge blocking included encouraging energy efficiency and conservation, as well as maintaining energy affordability for low-income customers. However, PGE has found that the current blocking rate does not align with the designed goals as the energy landscape continues to evolve. First, the energy charge blocking disproportionately impacts low-income households since the benefits are provided to low usage customers but not necessarily to low-income customers. Second, it provides a conflicting price signal in the context of support for electric vehicle adoption and makes transportation electrification less attractive. Finally, it adds complexity to PGE's TOD and Legacy TOU rate options, making the rates very hard to be understood for residential customers.

Low income does not simply translate into low usage. On the contrary, low-income customers tend to use more energy and are more frequently subject to higher block pricing than non-low-income customers. Low-income homes are more likely to be under-weatherized and have less efficient heating systems, two key drivers of winter usage. PGE estimates that approximately 20% of residential customers could be described as low income, meeting eligibility requirements for PGE's IQBD program.[3]

[3] Eligibility requirements are based on gross household income up to 60% of the State Median Income (SMI), adjusted for household size.

As shown in Figure 1, by using customer billing data from current IQBD participants as a proxy for low-income customers more generally, we see that low-income customers are more likely than non-low-income customers to exceed 1,000 kWh per bill, particularly during winter months. Between 2020 and 2022, 30% of low-income customers used more than 1,000 kWh in a typical month compared to 27% of non-low-income customers. During the winter months (November to April), the difference is starker: 39% of low-income customers compared to 32% of non-low-income customers. Winter energy bills tend to be higher for most residential customers, but the increase is greater for low-income customers, reflecting a higher prevalence of under-weatherization and inefficient heating systems.

Figure 1



PGE is also committed to supporting the growth of electric vehicles (EVs) and removing rate design barriers for charging during non-peak hours. The inclining block rate provides a disincentive for home charging at any time of day, ignoring the time-sensitive nature of the impacts of the additional load on PGE's system. Customer savings from switching from gasoline to electric as a vehicle fuel source will be dampened with an inclining block rate.

Finally, on May 1, 2021, PGE launched a new residential TOD rate which introduced a larger differential between on- and off-peak prices, muting the conservation signal from the energy charge blocking.[4] One of our primary goals in the design of the new TOD rate is to keep the rate structure as simple as possible, recognizing that residential customers want easy-to-use offerings and pricing. Removing the blocking aspect from the TOD rate would advance this goal significantly but also requires removing the blocking from the standard residential rate. PGE's TOD rate under Schedule 7 is designed to be revenue neutral compared to the standard residential rate, assuming similar use patterns within the residential class. To maintain the revenue neutrality of this rate, there needs to be a consistent energy rate structure.

Q. Do you incorporate a projection of the revenue impacts of the Schedule 7 voluntary portfolio TOU/TOD options in the calculation of Schedule 7 standard energy, transmission, and distribution prices?

A. Yes, but only for customers on the Legacy TOU option. We estimate that by continuing to price the voluntary Legacy TOU rate in a manner that presumes customers' load shape is the same as the overall rate schedule, PGE will incur a revenue shortfall of approximately $382,000. We incorporate this impact in the standard Schedule 7 energy, transmission, and distribution charges.

Q. Why are revenue impacts of the Schedule 7 voluntary portfolio TOD option not included in the calculation of Schedule 7 prices?

[4] PGE markets this residential offering as TOD on portlandgeneral.com and other customer-facing materials; however, this offering is currently labeled Time-of-Use in Schedule 7 of PGE's tariff. It is distinct from the Legacy TOU rate option that has been offered to residential customers for about 20 years. TOD references are labeled more clearly in PGE's E-19 tariff series submitted with this filing.

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 into the 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	**$22.00 per customer per month**
Basic Charge Three Phase	**$31.00 per customer per month**
Transmission & Related Services Charge	**6.37 mills per kWh**
Distribution Charge First 5,000 kWh	**63.43 mills per kWh**
Distribution Charge Over 5,000 kWh	**34.06 mills per kWh**
Energy Charge	**73.92 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 $55 for three-phase. We are proposing to increase the Basic Charge by $2.00 from the current $20 to $22 monthly amount for single-phase and from the current $29 to $31 monthly amount for three-phase. The Basic Charge was last increased in PGE's 2019 test year GRC, Docket No. UE 335 (UE 335); at that time, 14% of the customer's bill consisted of the Basic Charge. PGE's proposal to increase the Basic Charge by $2 results in 12% of the customer's bill consisting of the Basic Charge which is still below what was previously recovered in 2019. 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 Nonresidential 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	**$40.00 per customer per month**
Basic charge Three Phase	**$50.00 per customer per month**
Trans & Related Services	**$2.45 per on-peak kW**
Facility Capacity Charge (First 30 kW)	**$5.70 per kW Facility capacity**
Facility Capacity Charge (Over 30kW)	**$5.60 per kW Facility Capacity**
Distribution Demand Charge	**$1.56 per on-peak kW**
Generation Demand Charge	**$8.48 per on-peak kW**
COS Energy Charge On-peak	**52.53 mills per kWh**
COS Energy Charge Off-peak	**37.53 mills per kWh**
System Usage Charge	**10.51 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 $35 to $40 and the three-phase charge of $45 to $50. The Basic Charge was last increased in UE 335. Increasing the Basic Charge allows PGE to recover our embedded customer costs at the same percentage of the bill as in 2019. 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 $2.45 per kW of on-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 $1.56 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 which maintains the current on-and off-peak differential at 15 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 ratespread, 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	**$1,040.00 per customer per month**	**$920.00 per customer per month**
Trans & Related Services	**$2.45 per on-peak kW**	**$2.42 per on-peak kW**
Facility Capacity Charge (First 200 kW)	**$3.18 per kW Facility Capacity**	**$3.15 per kW Facility Capacity**
Facility Capacity Charge (Over 200 kW)	**$3.08 per kW Facility Capacity**	**$3.05 per kW Facility Capacity**
Distribution Demand Charge	**$1.56 per on-peak kW**	**$1.54 per on-peak kW**
Generation Demand Charge	**$9.56 per on-peak kW**	**$9.45 per on-peak kW**
COS Energy Charge On-peak	**51.18 mills per kWh**	**50.68 mills per kWh**
COS Energy Charge Off-peak	**36.18 mills per kWh**	**35.68 mills per kWh**
System Usage Charge	**2.48 mills per kWh**	**2.45 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 $1,040 and $920, 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 $2.45 per kW of on-peak demand for secondary service and $2.42 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 $1.56 and $1.54 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 which maintains the current on-and off-peak differential at 15 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	**$4,950.00 per month**	**$4,900.00 per month**	**$6,440.00 per month**
Transmission & Related Charge	**$ 2.45 per on peak kW**	**$2.42 per on peak kW**	**$2.38 per on peak kW**
Facility Capacity Charge First 4,000 kW	**$1.61 per kW Facility Capacity**	**$1.59 per kW Facility Capacity**	**$1.59 per kW Facility Capacity**
Facility Capacity Charge Over 4,000 kW	**$1.30 per kW Facility Capacity**	**$1.28 per kW Facility Capacity**	**$1.28 per kW Facility Capacity**
Distribution Demand Charges	**$1.56 per on-peak kW**	**$1.54 per on-peak kW**	**$0.12 per on-peak kW**
COS Energy Charge On-peak	**73.58 mills per kWh**	**72.85 mills per kWh**	**72.10 mills per kWh**
COS Energy Charge Off-Peak	**58.58 mills per kWh**	**57.85 mills per kWh**	**57.10 mills per kWh**
System Usage Charge	**2.05 mills per kWh**	**2.03 mills per kWh**	**2.01 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 $1.42 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 on- and off-peak differentiated by delivery voltage. We maintain the current differential of 15 mills per kWh, the same differential as for Schedules 83 and 85. 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	$20,300.00 per month	$20,300.00 per month
Transmission & Related Charge	$2.42 per on-peak kW	$2.38 per on-peak kW
Facility Capacity Charge First 4,000 kW	$1.75 per kW Facility Capacity	$1.75 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.44 per kW Facility Capacity	$1.44 per kW Facility Capacity
Distribution Demand Charge	$1.54 per on-peak kW	$0.12 per on-peak kW
COS Energy Charge On-peak (30-250MWa)	71.48 mills per kWh	70.68 mills per kWh
COS Energy Charge Off-peak (30-250 MWa)	56.06 mills per kWh	55.26 mills per kWh
COS Energy Charge On-peak (>250 MWa)	69.54 mills per kWh	68.76 mills per kWh
COS Energy Charge Off-peak (>250 MWa)	54.54 mills per kWh	53.76 mills per kWh
System Usage Charge (30-250 MWa)	1.90 mills per kWh	1.88 mills per kWh
System Usage Charge (>250 MWa)	1.85 mills per kWh	1.83 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 1.42/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 15.42 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. We propose to increase the monthly Basic Charge by $5 from $30 to $35 for single- and three-phase service customers. The Basic Charge was last increased in the 2019 test year GRC, Docket No. UE 335. Increasing the Basic Charge allows PGE to continue to recover its embedded customer costs at the same percentage of the bill as in 2019. We maintain the volumetric recovery of transmission and distribution costs and continue to differentiate the energy charges based on the on- and off-peak periods defined in Schedule 38. We increase the differential on- and off-peak hours from 15 to 20 mills per kWh. 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 propose to increase the Basic Charge by $2 from $37 to $39 per month, applicable during the months of May through October. The Basic Charge was last increased in the 2019 test year GRC, Docket No. UE 335; at that time 16% of the customer's bill consisted of the Basic

Charge. PGE's proposal to increase the Basic Charge by $2 results in 14% of the customer bill consisting of the Basic Charge which is still below what was previously recovered in 2019. 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 $5 from $45 to $50. The Basic Charge was last increased in UE 335; at that time 4% of the customer's bill consisted of the Basic Charge. PGE's proposal to increase the Basic Charge by $5 results in 3% 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 1305.

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 grandfathered services closed to additional governmental agencies.

V. Other Rate Schedule Changes

A. Decoupling

Q. What is decoupling?

A. There are various forms and applications of decoupling. At its core, however, decoupling is a form of revenue regulation that provides, "a tool to break the link between how much energy a utility delivers and the revenues it collects. Decoupling is used primarily to eliminate incentives that utilities have to increase profits by increasing sales, and the corresponding disincentives that they have to avoid reduction in sales."[5]

Q. Does PGE currently have a decoupling mechanism?

A. No, it does not.

i. Background on PGE's Prior Decoupling Mechanism

Q. Did PGE previously use a decoupling mechanism?

A. Yes. In its 2009 test year GRC, Docket No. UE 197 (UE 197), PGE proposed, and the Commission approved, its initial decoupling mechanism as a fixed cost-recovery, true-up mechanism consisting of a Sales Normalization Adjustment (SNA) for Schedules 7 and 32 and a Lost Revenue Recovery Adjustment (LRRA) for large nonresidential customers with loads less than one MWa. Since then, PGE had variations on the decoupling mechanism in place until May 2022.

Q. Please discuss the history of PGE's use of a decoupling mechanism.

A. In its 2009 test year GRC, UE 197, PGE proposed, and the Commission approved, its initial decoupling mechanism as a fixed cost-recovery, true-up mechanism consisting of a Sales

[5] Revenue Regulation and Decoupling: A Guide to Theory and Application, RAP, page 1, https://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf

Normalization Adjustment (SNA) for Schedules 7 and 32 and a Lost Revenue Recovery Adjustment (LRRA) for large nonresidential customers with loads less than one MWa. Subsequently, the Oregon Citizens' Utility Board (CUB) applied for Reconsideration of Order No. 09-020, Section IIIB.12, PGE Decoupling Proposal. CUB asked the Commission to consider whether decoupling was appropriate during a recession, whether decoupling should be based on marginal cost, not average fixed cost recovery per kWh, and whether the Commission should consider suspending PGE's decoupling mechanism for now and reserve it for more normal economic circumstances.

Q. How was PGE's initial decoupling mechanism in UE 197 modified by the Commission based on CUB's application for reconsideration?

A. The Commission declined to make extensive changes to PGE's two-year decoupling mechanism. However, the Commission concluded in Order No. 09-176 that the 2% "soft cap," which would cause amounts more than that figure to be transferred to interest-bearing deferred accounts to be recovered in rates after the two-year decoupling mechanism expired, should be modified to an absolute limit or "hard cap" upon PGE's recovery of fixed costs in usage-based rates.

Q. Did PGE propose changes to the 2% limiter in subsequent GRCs?

A. Yes, in Docket No. UE 335 in 2019, PGE proposed several structural changes, including changes to the 2% limiter. PGE proposed to keep the 2% limiter but include the ability to roll amounts over 2% to the subsequent year or years.

Q. Did the Commission approve any elements of PGE's proposed changes to its decoupling mechanism in UE 335?

A. In Order No. 18-464, the Commission declined all of PGE's proposed changes, except for PGE's request to move Schedule 83 customers under the SNA mechanism.

Q. Did PGE again propose structural changes to its decoupling mechanism in its next GRC?

A. Yes. In our 2022 GRC, Docket No. UE 394, PGE requested to extend decoupling through December 31, 2025 and proposed a limited number of simple, focused changes. PGE proposed to apply the SNA to Schedules 38/538, 47, and 49/549 and allow balances over the 2% limit to roll over to the subsequent year or years.

Q. Why did PGE propose these changes to the 2% limiter in UE 394?

A. A 2% limiter without a carryover creates an imbalance of risk and benefits between PGE and its customers. Good regulatory policy should provide a fair opportunity for PGE to recover prudently incurred fixed costs as approved by the Commission when it sets rates. In short, it should result in an alignment of interests on the key inputs in ratemaking. Instead, the asymmetric limiter creates an incentive for non-utility parties to propose increases to the load forecast in rate cases which, if adopted by the Commission, work in conjunction with the limiter to effectively deny recovery of the fixed cost portion of the Commission-approved revenue requirement. Decoupling as a concept should make the load forecast less of a focus and allow recovery of fixed costs; no more and no less. The purpose of the limiter is to mitigate price swings for customers.

A symmetrical balancing account that operates with rollovers of charges over the limiter aligns incentives for parties while providing the ability to better manage customer price variability. In addition, any charge in one year that exceeds the limiter can net against credits in future years, which can stabilize price impacts as well.

In PGE's opening testimony in UE 394, we proposed to alter PGE's decoupling mechanism and ultimately, through settlement negotiations, reached an agreement with parties to terminate the decoupling mechanism. This agreement was included as part of the Third Partial Stipulation for UE 394. After filing the Third Partial Stipulation, the Natural Resources Defense Council (NRDC) and Northwest Energy Coalition (NWEC), who at that point were not parties to the proceeding, filed an objection to the termination of PGE's decoupling mechanism. NRDC and NWEC then petitioned the Commission to intervene, which was granted with conditions. Ultimately, the Commission adopted the Third Partial Stipulation.

Q. Did the Commission include any directives as part of adopting the Third Partial Stipulation?

A. Yes. As part of Order No. 22-129, the Commission determined that since terminating PGE's decoupling mechanism occurred within the limited bounds of a stipulation with stipulating parties, there was a lack of meaningful opportunity for the Commission and other broader stakeholders to engage on important policy issues related to decoupling. As such, the Commission requested that PGE address decoupling in its next GRC. Specifically, the Commission directed, "PGE in opening testimony in its next GRC to more fully justify why the Commission should not implement a decoupling mechanism to incent electric efficiency even within a context of policy-driven electrification."[6]

[6] Docket No. UE 394, Order No. 22-129, page 17.

ii. Decoupling and Policy Goals

Q. How does PGE address the arguments that decoupling is needed to promote energy efficiency policies?

A. Due to the unique structure and circumstances in Oregon, energy efficiency (EE) has been successfully implemented both with and without decoupling. EE policies are established in law in Oregon and successfully implemented through the efforts of the Energy Trust of Oregon (ETO), working in partnership with PGE and other stakeholders. This success is demonstrated by the consistently strong energy efficiency savings achieved in PGE's service territory.[7] Further, the ETO now has over 20 years of experience, diligently working to pursue cost effective energy efficiency for customers of Oregon utilities. We think that, if properly designed and compatible with other regulatory mechanisms, decoupling can be an effective tool; even in a state like Oregon, which has a unique third-party delivery structure and history of highly successful results. To be effective and avoid creating conflicting incentives and undesirable outcomes, a revenue decoupling mechanism must fit with other key mechanisms. It is particularly critical to align the design elements and implementation of the revenue decoupling and Power Cost Adjustment Mechanism (PCAM) to ensure a complimentary set of regulatory policies that operate effectively together for the benefit of customers.

Q. Is decoupling necessary to promote policy-driven beneficial electrification?

A. No. Our interest is in timely, steady investment in beneficial electrification that advances state policy goals and is consistent with our work through the Transportation Electrification (TE) plan and other planning efforts. While proponents of decoupling may argue that decoupling helps to ensure that customers rather than the utility benefit from increased revenue received

[7] On a preliminary basis for 2022, the ETO has reported achieving 30.4 aMW relative to the goal of 29.0 aMW.

from beneficial electrification, that does not promote the long-term policy goals of beneficial electrification.

We acknowledge that the utility can potentially benefit between GRCs. However, that benefit is limited to the amount not included in the test year forecast. PGE includes those forecasted loads in our forecast for the test year. Decoupling could amount to a refund or a charge depending on the actual weather-adjusted energy deliveries compared to the forecast based on PGE's previous decoupling mechanism. In addition, decoupling is applied on a per customer basis, meaning additions or subtractions based on number of customers is a risk already borne by PGE. Decoupling would only cover additional load on existing service that is covered by the SNA, based on PGE's previous decoupling mechanism.

By allowing the utility to retain some, or all, of the additional fixed-cost related revenues, the Commission would encourage additional investments to occur between rate cases as the incremental revenues would help pay for a portion of the incremental costs of the investment. Otherwise, the incentive for the utility is to time such investments so that costs are incurred only when rate cases would provide for additional revenues to cover the costs of these investments.

Also, while proponents of decoupling may argue that the utility benefits from the increased load and revenue from electrification that will occur between rate cases, they overlook how the utility can use those funds as an alternative to customer price increases to support needed electrification investments. That is why a between-GRC refund of incremental revenues from beneficial electrification is at odds with the policy goals of the state to promote beneficial electrification. Therefore, decoupling — in the form previously used with PGE — is not necessary to ensure policy-driven beneficial electrification is pursued or occurs. That is not to say decoupling can never be a tool in beneficial electrification efforts. If properly constructed, decoupling can align stakeholders' mutual interest in beneficial electrification. However, to do that, decoupling must be constructed in a way that addresses PGE's significant concerns.

iii. Challenges with Decoupling

Q. What are PGE's concerns with PGE's previous decoupling mechanism that terminated on May 9, 2022?

A. PGE has two primary concerns. First, the prior mechanism had a 2% hard limiter per rate schedule on collections from customers. Any collections over 2% were lost and resulted in no recovery for the amount over 2%. Refunds greater than 2% did not have a limit. The asymmetry led to large price changes in the year after a significant refund (since the refund had no limit), in cases when the next year resulted in a collection.

Second, a decoupling mechanism that would serve to refund revenues to customers would have a detrimental impact on PGE's gross margin if PGE simultaneously experiences significant increases in power costs to serve higher than expected load. As discussed in PGE Exhibit 400, PGE's current PCAM has a wide and asymmetrical deadband that exposes PGE to substantial risk due to increasingly extreme energy market conditions.

Q. How is decoupling misaligned with PGE's existing PCAM mechanism?

A. For a revenue decoupling mechanism to be effective – properly adjusting for changes in customer usage patterns while remaining revenue and cost neutral – it must be matched with an appropriate PCAM that adequately addresses power cost variances between forecast and actuals. The decoupling mechanism is misaligned with the PCAM because it operates independently, and without regard for, the impact of changes in load on changes in power costs.

Q. Is this how decoupling mechanisms generally function elsewhere?

A. Yes. However, generally other states and utilities that have decoupling mechanisms also have full or nearly full pass-through of prudently incurred power and fuel costs as explained in PGE Exhibit 400.

Q. Can decoupling exacerbate financial volatility when weather events result in higher load to serve customers?

A. Yes. Decoupling can serve to create refunds of fixed cost margin at the same time as extreme high or low temperatures occur driving loads higher. As the cost to serve this incremental load would be based on high market power prices, the operation of the PCAM would likely result in PGE substantially under-recovering the associated incremental power costs. For example, in July 2021 a heat event occurred that resulted in approximately 800 MWa of additional load over the forecast established in power cost prices. The cost to serve that load was as much as ten times the forecasted power cost of $46 per MWh used to set power cost prices, exposing PGE to a material loss to reliably serve customer load for this event. Meanwhile, PGE accrued a $4 million decoupling refund associated with July 2021 results. While the heat event did not cause the decoupling refund (decoupling was based on weather-normalized loads), the operation of these two regulatory policy tools clearly worked at cross purposes with each other to exacerbate financial volatility.

iv. Requirements Before Pursuing Decoupling

Q. Is PGE requesting a decoupling mechanism in this GRC?

A. While we have not included a specific proposal in this rate case filing for a new decoupling mechanism, PGE is open to exploring the implementation of a revenue decoupling mechanism that is combined and compatible with a revised PCAM.

Q. If PGE were to propose a new decoupling mechanism that is compatible with a revised PCAM, please describe the mechanism.

A. PGE may consider a SNA mechanism for Schedules 7, 32, and 38 that compares actual weather-adjusted distribution, transmission, and fixed generation revenues that are collected on a volumetric basis with those that would be collected with a fixed per-customer charge, much like its previous mechanism. The difference would accumulate in a balancing account and refunded or collected over a future period. PGE would propose a 3% annual limit on collections and refunds to mitigate the price impact on customer bills but allow collection or refund amounts in the balancing account that exceed the 3% limit to carry forward to the subsequent year (or years) for refund or recovery. PGE Exhibit 1306 provides an example of how the mechanism would look in tariff form.

Q. How would PGE propose to handle new residential customers that connect to PGE's system in subsequent years between GRCs?

A. PGE would propose a secondary fixed charge at a reduced rate for customer accounts over the forecast set in a GRC since typically new residential customers are expected to have lower average energy use compared to PGE's existing average residential customer use.

Q. Why would PGE not propose an LRRA mechanism for large commercial and industrial customers?

A. In PGE's last GRC, PGE introduced generation demand charges for Schedule 83 and 85, thus allowing PGE to collect for fixed costs that were previously collected volumetrically, mitigating the need for such a mechanism. Additionally, a LRRA mechanism would be administratively challenging. PGE's experience with the previous LRRA mechanism found it to be administratively burdensome with results that were largely immaterial compared to the revenues from the applicable rate schedules.

B. Retire PGE's Legacy Residential Time of Use Rate

Q. What does PGE propose with regard to residential voluntary time-of-use rates?

A. PGE proposes to close its residential Legacy TOU rate option to new enrollments and modify PGE's residential TOD rate option. After the Legacy TOU option is closed to new enrollments, PGE plans to communicate with existing customers on this rate to help them migrate to default service on Schedule 7 or TOD, depending on which rate best meets their needs. For customers who opt for TOD, PGE will educate them on the TOD rate structure and provide tips on load shifting to help minimize their bills. PGE will retire the Legacy TOU offering within Schedule 7 on December 31, 2024.

Q. Why does PGE propose to close and eventually retire its residential Legacy TOU rate option?

A. PGE's residential Legacy TOU rate was introduced 20 years ago, following the SB 1149 directive for increased customer rate options. The rate has a complex, seasonal pricing structure designed to incent residential load shift away from morning, daytime, and evening hours to overnight hours, depending on time of year. While the off-peak price is low, prices between 6 a.m. and 10 p.m., Monday through Saturday are notably higher than the Schedule 7 default price (combining energy, transmission, and distribution charges). The complexity of the rate structure and the relatively high morning, daytime and evening prices have made Legacy TOU attractive to a very limited set of PGE customers, some of whom could expect to see decreased bills on TOD or the Schedule 7 default price.

Customer enrollment in Legacy TOU has been low and has recently decreased, further limiting the load shift benefits to PGE's system and the wider customer base. Since introducing the new TOD rate in mid-2021, Legacy TOU enrollments have decreased by about 10% to 2,200 customers, compared to over 7,000 new enrollments on TOD. In response to the low take-up of Legacy TOU and extensive customer research,[8] the pricing structure of TOD was designed to be simple for customers to understand and incorporate into their energy usage patterns, incenting customers to shift load away from PGE's most frequent and costly peak hours. While load shift impacts under the new TOD offering have yet to be evaluated,[9] TOD prices more closely align with the temporal distribution of PGE's marginal costs, efficiently recovering capacity and energy-related costs from enrolled customers.

PGE offers residential customers a range of rate and program options that encourage load shifting and peak reductions, providing opportunities for customer savings and contributions to system benefits. We propose simplifying our optional residential price plans to TOD only to minimize confusion among customers and to streamline our efforts in optimizing the portfolio of residential offerings, including TOD, Peak Time Rebates, EV Charging and a wide range of pilot programs: demand response, direct load control, energy storage.

[8] PGE conducted a flexible load rate pilot between 2015-2017 to assess customer response to and satisfaction with a range of time-of-use and demand response rate structures See Docket No. UM 1708 for more information.
[9] Per Commission approval of Staff recommendation in Docket No. ADV 1194, PGE, a third-party evaluation of PGE's TOD optional rate is underway and will be completed by Q3 2023.

Continuing to manage, update and educate customers about PGE's Legacy TOU rate is not outweighed by the modest customer interest and satisfaction with the rate, nor the modest system benefits provided by participants.

Q. What changes does PGE propose for its residential TOD rate?

A. PGE is proposing minor adjustments to its residential TOD rate that moves one mid-peak hour to on-peak, extending the on-peak window from 5 to 9 p.m. to 4 to 9 p.m. Increasing the portion of on-peak hours over which costs can be spread tempers the size of the on-peak price increase in 2024. The on-peak price will increase from $0.328 to $0.394 per kWh. A commensurate price increase to the mid-peak window, from $0.119 to $0.154 per kWh, maintains its relative placement just below the combined Schedule 7 default service of $0.159 per kWh. The increase to off-peak prices is minimal, from $0.074 to $0.083 per kWh, to benefit and incent overnight EV charging while maintaining a cost basis.

Table 8
Schedule 7 – Optional Time-of-Day

Peak Window		Prices
Basic Charge – Multifamily		**$10.00 per customer per month**
Basic Charge – Single Family		**$13.00 per customer per month**
On-peak	**Monday-Friday, 4 to 9 p.m.**	**394.3 mills per kWh**
Mid-peak	**Monday-Friday, 7 a.m. to 4 p.m.**	**154.0 mills per kWh**
Off-peak	**Monday-Friday, 9 p.m. to 7 a.m.** **All hours on weekends and holidays**	**83.2 mills per kWh**

Q. To close the residential Legacy TOU rate to new enrollments and retire the rate, does the Commission need to take specific action?

A. Yes. In PGE Advice No. 20-34/Docket No. ADV 1194, the Commission adopted Staff's recommendation to approve PGE's new TOD rate. Condition 1 in Staff's memo requires PGE's Legacy TOU "rate to remain open until such time that the Commission approves a new, residential charging focused TOU rate, and decides closing the rate is in the public interest."[10] PGE requests approval from the Commission in this GRC to close the Legacy TOU rate to new enrollments and retire the rate at the end of 2024.

Q. Does PGE propose any other changes to residential options in Schedule 7?

A. Yes. PGE proposes extending allowable event hours within the Peak Time Rebate (PTR) program to better align with the change in TOD on-peak hours (4 p.m. to 9 p.m.). Currently, load reduction events can be called for two to five consecutive hours between 7 a.m. and 11 a.m. or 3 p.m. and 8 p.m., except on holidays. Extending the evening hours to 9 p.m. would make the window in which PGE could call an event fully encompass TOD on-peak hours, creating a consistent load shift signal to residential PTR and TOD participants. This recommendation would not affect the duration of future events or the rebate amount. Both the TOD and PTR minor structural changes will also be shared in the upcoming Flexible Load Multi-Year Plan process (Docket No. UM 2141).

C. Schedule 122 (Storage in Renewable Resources Automatic Adjustment Clause)

Q. What 2024 changes do you propose for Schedule 122?

A. Schedule 122 is PGE's renewable energy resources automatic adjustment clause (RAC). We propose to clarify that standalone energy storage that is used to integrate and firm renewables on a utility's system qualifies as "associated energy storage." SB 1547 directs the Commission to establish an automatic adjustment clause as defined in ORS 757.210 or another method to allow timely recovery of prudently incurred costs for the utility to construct or acquire renewable resources, associated transmission, and associated energy storage. PGE's resources are system resources. Any energy storage facility on the system controlled

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[10] PGE Docket No. ADV 1194/Advice No. 20-34 Requests Updates to Schedule 7 Residential Service Time of Use Rate, https://edocs.puc.state.or.us/efdocs/UBF/adv1194ubf152051.pdf, page 1.

by PGE provides integrating and firming renewable energy resources as a primary system benefit. PGE requests that the Commission clarify that energy storage used to integrate renewables on a utility's system qualifies as "associated energy storage."

Q. Why is PGE proposing the change to Schedule 122 in this GRC?

A. In UE 335, PGE's 2019 GRC, PGE made a similar proposal to include energy storage resources in Schedule 122. However, PGE did not yet have standalone energy resources under procurement from an RFP at that time. Therefore, PGE agreed to modify the proposal to include the phrase "associated energy storage" in the tariff provision and proposed to determine what "associated" meant in a later proceeding. In Order No. 18-464, the Commission adopted PGE's proposal to determine the meaning of "associated" in that later proceeding. Based on the shortlist from the 2021 All-Source Request for Proposals (RFP), PGE expects to have standalone energy (battery) resources online in late 2024/early 2025. These energy storage resources will be used in part, to integrate and firm the growing number of PGE's intermittent renewable energy resources, which contribute toward PGE's achievement of Oregon's Renewable Portfolio Standards (RPS) and Oregon House Bill (HB) 2021 Clean Energy Plan (CEP) targets. Given that these resources will be in-service in the next two years, now is the time to clarify the meaning of "associated storage" in the RAC, where PGE proposes the clarification to Schedule 122 that "associated storage" includes any energy storage used to integrate and firm renewable resources. Additionally, recent legislative changes at the federal and state level further promote the use of energy storage and achieving more ambitious renewable energy targets by 2030 and 2040, emphasizing the importance of energy storage resources for achieving RPS and HB 2021 CEP targets adding to the timely nature for determining the meaning of "associated storage."

Q. Please summarize the federal legislation, which further promotes the use of energy storage resources.

A. The Inflation Reduction Act (IRA), passed in 2022, recognizes the importance of energy storage resources for carbon reduction to address climate change through the extension and expansion of Investment Tax Credits (ITC) for stand-alone energy storage. This legislation also provides an "opt-out" of normalization requirements for energy storage public utility property with a maximum capacity greater than 500 kW. The changes in tax incentives in the IRA create parity in the tax incentives between co-located and standalone projects and will provide PGE customers with enhanced economics for additional resource options to provide carbon-free capacity resources and to integrate renewable resources. Following the passage of the IRA, PGE allowed bidders on the 2021 RFP final shortlist the opportunity to update bid pricing to reflect the IRA tax credit benefits to ensure the value of the federal legislation was captured in the 2021 RFP resource acquisition process on behalf of customers.

Q. Please summarize recent Oregon legislation which pertains to clean energy targets and emissions-free resources.

A. HB 2021 sets additional planning framework and greenhouse gas reduction targets for investor-owned utilities in Oregon. Established in HB 2021, ORS 469A.415 directs utilities to demonstrate "continual progress" towards meeting the clean energy targets and that these actions and investments include not only new clean energy resources but also development of "supporting infrastructure" and "changes in system operation and other necessary action."

Q. How does PGE use energy storage to integrate and firm renewables on its system?

A. Energy storage resources can be rapidly dispatched and deployed at large or very small scales due to their modularity, can be easily sited and quickly developed, and have zero direct emissions. Renewable resources require a flexible grid, and storage has the potential to provide the types of balancing and grid reliability services (e.g., Frequency Response and Contingency Reserve) that are needed to do that. As Oregon moves to a more sustainable and greener future by using more and more renewable resources, and as stated above, the use of energy storage will increasingly be used to integrate and firm significant quantities of renewable energy to allow flexibility on the system.

Q. Please explain in more detail the renewable integration and firming services provided by energy storage.

A. Energy storage supports the integration and firming of renewables on our system by providing necessary reliability functions that renewables cannot reasonably provide themselves. As PGE moves to aggressively decarbonize its energy portfolio, energy services traditionally supported by non-renewable generating resources will need to be delivered from non-emitting resources to reliably support the integration of new renewables on the system. Energy storage is a controllable, non-emitting resource that will be crucial in providing firm energy services as described below:

1. Generation Capacity – Energy Storage can provide controllable generation capacity to the system during peak times when it is needed most. This offsets the need to procure additional generation resources.
2. Frequency Regulation – Energy Storage can ramp up/down quickly to adjust for energy imbalances in support of systemwide frequency regulation. Renewable energy resources cannot ramp up to meet the needs of frequency regulation except in circumstances where they are artificially curtailed in anticipation of a regulation

up need (not economic). As more renewables come online to displace non-renewable generation, PGE's need for frequency regulating resources will increase.

3. Load Following – Energy Storage can ramp up/down in response to a market signal to adjust for energy imbalances in support of balancing needs across the California Independent System Operator (CAISO) footprint. PGE's participation in the CAISO energy imbalance market is specifically tied to facilitating the integration of more renewables on the system. Renewable energy resources cannot ramp up to meet load following needs except in circumstances where they are artificially curtailed in anticipation of a regulation up need (not economic). As more renewables come online to displace non-renewable generation, PGE's need for load following resources will increase.
4. Contingency Reserves – Energy Storage can be brought online quickly in response to an unplanned transmission/generation outage. Intermittent renewable energy resources, such as wind and solar, cannot be called on to support energy needs following an unplanned outage and cannot be controlled.
5. Frequency Response – Energy Storage can immediately respond to changes in system frequency and deliver or absorb energy as needed to arrest short term frequency deviations resulting from unplanned system disturbances. Renewable energy resources do not have a high inertial response to system disturbances and cannot be depended on to support energy needs following frequency events.

Q. How does PGE plan for storage resource needs associated with renewable energy resources?

A. While current long-term planning does not specifically define an additional need for storage to integrate and firm renewables, PGE's Integrated Resources Plan (IRP) team has identified this as a gap as PGE and the region decarbonize. Initial work toward this goal was introduced in the development of the 2023 IRP, and PGE is working with stakeholders toward developing and defining these requirements in future IRPs.

Q. How does standalone energy storage differ from energy storage resources which are co-located (i.e., proximate or hybrid facilities)?

A. Standalone energy storage is located at a distinct interconnection point, not with a utility scale renewable energy resource, whereas co-located energy storage resource is in the same physical proximity to a renewable resource at an interconnection point. Energy storage provides enhanced system flexibility and the ability to integrate intermittent renewables whether standalone or co-located. The difference between a standalone storage facility and co-located one is the location-dependent benefits (e.g., local voltage management, transmission congestion relief, etc.).

Q. Please summarize PGE's proposal regarding Schedule 122.

A. PGE requests the Commission acknowledge that "associated storage" includes standalone energy storage used to integrate and firm renewable energy resources and provide the system benefits described above.

D. Schedule 125 Updates

Q. What changes do you propose for Schedule 125?

A. As it currently stands, Schedule 125 allows only for a limited number of power cost updates in years when PGE does not file a GRC. Given the significant changes in the current energy market environment that create new and rapidly evolving operational challenges impacting PGE's power operations, there is an increased need for year-to-year net variable power cost (NVPC) forecast modeling flexibility. Therefore, we are proposing modifications to the Schedule 125 guidelines to allow the application of NVPC forecast modeling enhancements in non-GRC years. We provide additional detail regarding this proposal in PGE Exhibit 300, Section II. Exhibit 1307 provides the red-line Schedule 125, outlining the proposed changes.

E. Schedule 126 Updates

Q. What changes do you propose for Schedule 126?

A. Schedule 126 provides the guidelines for the annual PCAM. We are proposing a PCAM reform that would rebalance the power cost risk between PGE and customers. We describe in PGE Exhibit 400 the proposed updated PCAM structure and why a PCAM reform is warranted at this time. To align Schedule 126 with the proposed PCAM changes, we have modified the guidelines for calculating the annual Power Cost Variance within the tariff schedule. Exhibit 1308 provides the red-line Schedule 126, reflecting the proposed changes.

F. 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. Is PGE proposing to remove any charges from Schedule 300?

A. Yes. PGE proposes to remove the following Schedule 300 charges:

- Service Locate and Long-Side Service Connection charges (Rule I Section 3) because they are not part of PGE's current business and PGE has not received a request to perform these services for several years.
- Charges for Submersible Transformers (Rule I Section 3) when no other restrictions apply and the Applicant is only considering a submersible transformer for aesthetic reasons.
- Customer Interval Data (12 months) to Customers charge (Rule F) because it is no longer part of PGE's current business; customers can see their interval data for free by logging into their account on the Portland General website.

Q. Is PGE requesting any methodology changes to how Schedule 300 charges are calculated or applied?

A. Yes. PGE requests that the following charges be priced at estimated actual costs per project:

- Trenching or Boring services (Rule I). When these services are requested, the costs will be assigned directly to the requesting customer. The customer will pay the estimated actual costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits. Additionally, the customer is typically responsible for contracting this service unless the customer specifically requests PGE provide these services.
- Installation of conduit on a wood pole for lighting purposes be priced at estimated actual cost, rather than a flat rate per pole.

Q. Please explain PGE's decision to change the pricing method of trenching and boring to estimated actual cost.

A. Trenching and boring is a service that can be highly variable based on the services requested, labor costs, and unique circumstances of each job. This necessitates the flexibility for PGE to tailor the cost of trenching and boring to the customer's needs.

Q. Has PGE performed trenching and boring services in the last five years?

A. In the last five years PGE has not performed trenching and boring services for new service connections driven by customers, nor projects motivated by municipalities. This is a non-standard practice and infrequently requested.

Q. Please explain PGE's decision to change the pricing method of installation of conduit on a wood pole for lighting purposes to estimated actual cost.

A. Installation of a conduit on a wood pole for lighting purposes is an infrequent service that is variable in the type of wood pole and the conduit needed for install. This necessitates the flexibility for PGE to tailor the cost of the installation of conduit on a wood pole for lighting purposes to the customer's need.

Q. Please describe the 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	$1,077	$1,146
Metered Temp - Existing Service	$819	$870
Metered Temp OH - Perm Service	$607	$670
Metered Temp UG - Perm Service	$632	$672
Enhanced Temporary Service (Gold-Temp) Unmetered Fixed Feed	$865	$963
Fixed Fee per 6-Month Renewal	$354	$415

- PGE's Wasted Trip Charge (Rule I Section 3) has been updated to reflect current costs. PGE is proposing a Wasted Trip Charge of $180. The current price is $100. This increase reflects PGE's 2024 forecasted labor costs. PGE has not updated the Wasted Trip Charge in over 20 years.

- PGE is proposing a Research PCB Content-Specific Transformer charge of $82. The current price is $75 per transformer. The increase in PGE's Research PCB Content-Specific Transformer charge is reflective of its 2024 forecasted labor costs.
- 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 $140. The current price is $80. PGE is proposing a non-network meter read charge of $25. The current price is $17 per month. These rates were last updated in January 2019. The increase in these charges is reflective of PGE's 2024 forecasted labor costs.
- Credit Related and Customer Requested Disconnection and Reconnection Rates (Rule H) rates have been updated to reflect current costs. PGE's proposed Credit Related and Customer Requested Reconnection Rates are shown in Table 10 below:

Table 10
Current and Proposed Credit Related and Customer Requested Reconnection Rates

Rate Type	Current Price	Proposed Price	Average Charges per Year (2018-2022)
Standard Meter Base	**$27**	**$50**	**6,557**
Standard Other than Meter Base	**$75**	**$145**	**19**
After Hours Meter Base	**$80**	**$190**	**386**
After Hours Other than Meter Base	**$160**	**$370**	**0**

- Billing Rates (Rules C, E, F, H, J, M and Sch 201) have been updated to reflect current costs. PGE's proposed Billing Rates are shown in Table 11 below:

Table 11
Current and Proposed Billing Rates[11]

Rate Type	Current Price	Proposed Price	Average Charges per Year (2018 –2022)
Special Meter Reading Charge (non-network)	$17	$25	1,268
Meter Test Charge	$75	$140	0
Field Visit Charge	$20	$50	2,618

PGE is proposing to update and add the Monthly Service Charge charged to Qualified Facilities (QFs) in Schedules 201 and 202 to Schedule 300. The current Monthly Service Charge is $10 per month and has not been revised since 2000. PGE is proposing to revise the charge to $151 to reflect PGE's activities to support processing credit payments to QFs, reviewing and monitoring communications to QF meters, supporting QF reporting, compliance and correspondence with QFs and renewable energy credits (REC) reporting to WREGIS. This change only affects new QFs contracting with PGE. This change does not affect any previous QFs who entered into a fixed price contract with PGE prior to the effective date of the GRC. Schedule 201 is not included in PGE's tariff, its purpose is to provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a QF to PGE. Information about Schedule 201 can be found on PGE's website in the Interconnection Resource Library.[12] Exhibit 1309 provides the red-line Schedule 201, reflecting the proposed change.

[11] The Meter Test and Field Visit Charges have not been updated in the last 19 years. The Special Meter Reading Charge was last updated in January 2019.
[12] PGE Interconnection Resource Library, https://portlandgeneral.com/renewable-installers/interconnection-resource-library.

G. Customer Ownership of Substations

Q. Please summarize PGE's concerns related to implementing the Schedule 90 Subtransmission Rate in UE 394.

A. When prompted by Staff and AWEC to implement a subtransmission rate for Schedule 90, PGE raised several concerns around the safety and maintenance of customer-owned substations, including, but not limited to: aging technology, difficulty in communication with the systems in customer-owned substations, as well as issues with the interconnection point with the PGE-owned grid and being able to safely disconnect the customer for maintenance or other work. These problems can create downstream issues that impact PGE's ability to provide safe and reliable power to other customers near a customer who receives power on a subtransmission rate.

Q. What does PGE propose to resolve concerns with the safety of customer-owned substations?

A. PGE is in the process of consulting with internal Subject Matter Experts to put together a proposal for updates to Rule C of the tariff that will outline safety and maintenance standards that customers must adhere to when taking service on a subtransmission rate. Because PGE wants to be thoughtful about these safety and maintenance standards, no changes are being recommended in this GRC and will instead happen through the process of a separate Rule C update.

H. Rules and Regulations

Q. Please describe PGE's proposed changes to Rules and Regulations.

A. PGE is requesting the following Rules and Regulation changes:

- Remove language in Rule I Section 3 B 3 that says, "where the Company provides trenching and back filling for installation of applicable residential underground service laterals, the charges specified in Schedule 300 will apply." PGE is updating the language to say, "Where the Company provides trenching and backfilling, estimated actual costs will apply as specified in Schedule 300."
- Remove Section 3B.4 from Rule I that allows an Applicant to request a submersible transformer for aesthetic purposes when no other restrictions apply and pay the cost set forth in Schedule 300. PGE is requesting to strike this provision from Rule I because the maintenance and repair over the life of a Submersible Transformer is higher than a standard Padmount Transformer. This ongoing O&M cost to maintain the Submersible Transformer is borne by all Customers, not just the Customer who initially selected and paid for the Submersible Transformer when their new service is installed. PGE will continue to install Submersible Transformers – they have become a standard piece of equipment in certain parts of PGE's Service Territory such as Urban areas where there is limited space and a pad-mount transformer cannot be installed. If a Submersible Transformer is required due to the building site's footprint, PGE includes the cost in its design estimate.
- Remove Sections 3D.1 and 3D.3 from Rule I because the Service Locate and Long-Side Service Connection charges are not part of PGE's current business.

- Change the language of Rule I Section 3A.2, Applicability of Special Conditions for Underground Line Extensions to include resiliency as a reason why Underground Line Extensions will be made. PGE is seeking the ability to require a new line extension to go underground if the address is in a high-risk fire zone or resiliency zone.
- Remove language in Rule F Section 5.K related to the Schedule 300 charge for unformatted and unanalyzed interval data usage. As noted above, this charge is no longer necessary because Customers can see their Interval Data for free by logging into their account on the Portland General website.

I. PGE Tariff E-19

Q. Why is PGE introducing a new E-19 Tariff series?

A. PGE's current E-18 Tariff has been in effect since January 16, 2007, with the Docket No. UE 180 (UE 180) GRC Compliance filing. Prior to UE 180, PGE issued a new tariff with every GRC filing. PGE's current E-18 Tariff has been in effect for 16 years and reflects a long history of additions and changes. PGE proposes a new E-19 Tariff to correct formatting inconsistencies and other minor miscellaneous changes, all considered housekeeping in nature. PGE does not propose any structural changes to the Tariff.

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.

List of Exhibits

Exhibits	Description
1301	Proposed Tariff Changes
1302	Estimated Impact of Proposed Changes on Customers
1303	Rate Design
1304	Allocation of Costs to Customer Classes
1305	Streetlight and Area Lights
1306	Decoupling Tariff Example
1307	Schedule 125 Redline
1308	Schedule 126 Redline
1309	Schedule 201 Redline

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SCHEDULE 4
MULTIFAMILY RESIDENTIAL DEMAND RESPONSE WATER HEATER PILOT

PURPOSE

The Multifamily Residential Demand Response Water Heater Pilot is a demand response option for eligible Multifamily Properties. The objectives of the Multifamily Residential Demand Response Water Heater Pilot are:

- To quantify the energy consumption that can be shifted to different times from:
  - Water heaters equipped with a communication interface that supports Direct Load Control Events, or
  - Water heaters retrofitted with a control switch in the power supply to the tank
- To inform further the program design for a water heater demand response program;
- To determine an appropriate incentive level for Multifamily Property Owners and Residential Customers who choose to participate in a demand response program for water heaters;
- To integrate and test different technologies; and
- To implement different demand response dispatch strategies.

DEFINITIONS

<u>Customer Override</u> – The ability for the Residential Customer to temporarily suspend Direct Load Control for a period of 24 hours.

<u>Direct Load Control</u> – The means for a utility to remotely control an appliance. In terms of this pilot, direct load control allows the Company to control when the water heater uses electricity to heat water.

<u>Direct Load Control Event</u> – A period in which the Company will provide Direct Load Control.

<u>Conventional Electric Resistance Water Heater</u> – Multifamily Property Owners' existing electric resistant water heaters will be retrofitted to be demand response enabled. Water heaters that require replacement will be replaced with smart electric resistance water heaters with the approval of the Multifamily Property Owners.

<u>Heat Pump Water Heater</u> – Models compatible with the Company's available hardware, software, and communication technology that can engage in direct load control events.

AVAILABLE

In all territory served by the Company where the Company's demand response communication networks are available.

SCHEDULE 4 (Continued)

APPLICABLE

Subject to selection by the Company, Multifamily Property Owners may participate in the pilot. Residential Customers in multifamily residences (MFRs) will be the primary target of the pilot. In cases of rental properties, the pilot will be structured as an opt-out program, meaning Residential Customers will be automatically enrolled in the pilot if their Multifamily Property Owners enrolls in the pilot and the Residential Customer must withdraw from the program if they do not want to participate.

Residential Customers will be given notice about this pilot at the time of installation of the communication interface or at the start of their service. The Company will provide Residential Customers with information that they will be automatically enrolled in the pilot if they do not opt out. The notice will also provide the Residential Customer the contact information and instructions on how to opt out of the pilot at the time of installation or at the start of their service. If a Residential Customer chooses to opt out of this pilot, the installed communication interface and any other installed Company equipment will remain on the water heater. A Residential Customer that has elected to opt out will be removed from the dispatch of direct load control events. As new Residential Customers move into a participating MFR. The Company will be aware of a new Residential Customer based on customer data from the Company's Customer Information System (CIS). The number of eligible Residential Customers to participate in the pilot is 18,000 customer households. Residential Customers will remain on Schedule 7 and will be eligible for the incentives described in this schedule.

ELIGIBILITY

For MFRs, the Company will initially select large complexes, negotiating with Multifamily Property Owners or their property manager for the installation of retrofit devices as well as new demand response enabled water heaters. At the Company's discretion, the Company will select qualifying properties based on number of apartments, size of apartments, occupancy, and size of existing water heater.

DIRECT LOAD CONTROL EVENT

During the pilot there will be no limitation on the hours of Direct Load Control Events. This pilot will offer the ability for the Residential Customer to override a direct load control event, under the terms listed in Special Condition 4 of this pilot.

ENROLLMENT

The MFR enrollment period will be through July 31, 2023. PGE will enroll MFRs by contracting with the Multifamily Property Owners or their property manager. Unless this pilot is otherwise terminated, MFRs and participating Residential Customers will be enrolled for the entire pilot term.

SCHEDULE 4 (Continued)

INCENTIVES

Multifamily Property Owners or their property managers will receive an annual incentive in the form of: a monetary payment, and/or a specified number of replacement water heaters and/or, a monetary contribution toward water heater servicing/replacement costs. PGE will negotiate specifics with participating Multifamily Property Owners or their property managers based on their preferences.

PGE will also incentivize the costs for new smart electric water heaters for Multifamily Property Owners or their property managers in situations when the existing water heater is too old to be retrofitted cost effectively and/or when an existing electric water heater fails. PGE will pay the incremental cost between a water heater with a standard six (6) year warranty and a qualifying smart water heater. Incentives should cover all or most of the cost difference between a standard electric water heater and a smart electric water heater. The incentive will substantially reduce the costs of making the water heater demand response enabled.

The Residential Customer will also receive an incentive. The incentive that the Residential Customer receives may differ from the incentive of the Multifamily Property Owners or their property managers. The incentive amounts for each MFR, Multifamily Property Owners or their property managers will be determined based on the total number of demand response enabled water heaters installed or active participation levels in demand response events.

SPECIAL CONDITIONS

Residential Customer

1. The Residential Customer may terminate participation under this pilot voluntarily. The Residential Customer will not receive a participation incentive if they withdraw or are removed from the pilot. The Residential Customer must notify the Company to withdraw from the pilot.

2. If a Residential Customer withdraws or is removed from the pilot, the Residential Customer is not eligible for reenrollment during the pilot.

3. If the Residential Customer moves from the enrolled residence during the term of the pilot, they are no longer eligible for the pilot.

4. The Residential Customer may activate a 24-hour suspension from the pilot by notifying PGE through a pilot specific customer service phone number on the Company’s website. A Residential Customer may be removed from the pilot if they implement the override option excessively; an example of excessive is override use for more than 100 days, or more than 15 days in any 30-day period.

5. To receive a participation incentive, the Residential Customer must respond to seasonal surveys regarding the pilot.

SCHEDULE 4 (Concluded)

SPECIAL CONDITIONS (Continued)

Company

6. The Company has the right to remove a MFR or Residential Customer from the pilot at any time, for any reason.

7. The Company is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating MFR, Multifamily Property Owners and their property managers, Residential Customer, or third parties that result from Direct Load Control Events.

8. Communication interfaces installed onto the water heater will remain the property of the Company before, during and after the conclusion of the pilot.

9. The provisions of this schedule do not apply for any time period that the Company interrupts the Residential Customer's load for a system emergency or any other time that a Residential Customer's service is interrupted by events outside the control of the Company.

DATA COLLECTION

In consideration for being allowed to participate in the Pilot, Multifamily Property Owners and Residential Customers agree that the Company or its representative may collect certain information from Multifamily Property Owners and Residential Customer's participation in the Pilot and use such information as described herein. Such information may include, but is not limited to, general energy usage and associated account and billing data (such information includes, but is not limited to, consumption and billing data, billing records, billing history, meter usage data, and rate information), name, email address, service address, account number, appliance serial number, activation date, runtime data, set-points, application and survey information. This data will be retained by the Company and its representatives for an indefinite amount of time. Multifamily Property Owners and Residential Customer agree that the Company and its Pilot representatives may use the information obtained through Pilot participation (a) to operate, administer, market, evaluate, analyze, change or improve the Pilot or utility services, (b) for the Company to prepare and present general, aggregated or anonymized results and information about the Pilot to third parties, including governmental entities such as the electricity system regulatory bodies, (c) for the Company to understand and evaluate participant habits and to inform the development and creation of utility programs and load planning, and (d) to inform Multifamily Property Owners and their property managers of irregularities associated with a given water heater. The Company and its Pilot representatives and agents will not use the data collected in the Pilot except as provided herein and will not otherwise disclose, transfer or sell this data.

TERM

The duration of this pilot is through July 31, 2023.

SCHEDULE 5
RESIDENTIAL DIRECT LOAD CONTROL PILOT

PURPOSE

This direct load control pilot is a demand response option for eligible Residential Customers. The direct load control pilot offers incentives to allow the Company to control thermostats during Direct Load Control Events while providing a customer override. The Company provides advance notice to participating Customers for Direct Load Control Events. The pilot is expected to be conducted from December 1, 2015 through June 30, 2025.

AVAILABLE

In all territory served by the Company.

APPLICABLE

This program is available to up to 80,000 eligible Residential (Schedule 7) Customers that elect to enroll and participate in the pilot. Customers will remain on Schedule 7 and will be eligible for the incentives described in this schedule.

DEFINITIONS

Central Air Conditioning – Air conditioner tied into a central ducted forced air system.

Direct Load Control – A remotely controllable switch that allows the utility to operate an appliance, often by cycling. In terms of this pilot, direct load control allows the Company to change the set point or cycle the Customer’s heating or cooling through the Customer’s Qualified Thermostat to reduce the Customer’s energy demand.

Direct Load Control Event – A period in which the Company will provide direct load control.

Ducted Heat Pump – Heat pump heating and cooling system hooked into a central ducted forced air system.

Electric Forced Air Heating – An electrical resistance heating system tied into a central ducted forced air system.

Event Notification – The Company will issue a notification of a Direct Load Control Event to participating Customers. Notification methods may include email, text, auto-dialer phone call, on thermostat display screen, or via mobile app notification. Notification may also be available on the Company’s website.

Event Season – The pilot has two event seasons: the Summer Event Season and the Winter Event Season.

SCHEDULE 5 (Continued)

DEFINITIONS (Continued)

Holidays – The following are holidays for purposes of the pilot: New Year's Day (January 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.

Qualified Thermostat – Thermostats that are Company-approved and listed on PortlandGeneral.com.

Summer Event Season – The summer event season includes the successive calendar months June through September.

Winter Event Season – The winter event season includes the successive calendar months December through February.

ELIGIBILITY

Eligible Customers must have a Network Meter and connectivity to the internet. To participate in the Winter Event Season, the Customer must have a Ducted Heat Pump or Electric Forced Air Heating. To participate in the Summer Event Season, the Customer must have Central Air Conditioning or a Ducted Heat Pump.

DELIVERY CHANNEL

BRING YOUR OWN THERMOSTAT

This delivery channel allows the Customer to use their Qualified Thermostat, which must be connected to the internet and the heating or cooling system, all at the Customers' expense, to participate in Direct Load Control Events and receive incentives. Participating Customers receive a one-time payment of up to $105 for signing up for this delivery channel. In addition, Customers receive $25 for each Event Season they participate. A Customer participating in all Event Seasons receive up to $155 for the first participating year and $50 for additional years. Incentives are paid to the Customer with a check, bill credit, generic gift card, or credit. To receive payment for an Event Season, the Customer must participate in at least 50% of the event hours for which the Customer is eligible to participate in that Event Season.

SCHEDULE 5 (Continued)

DELIVERY CHANNEL (Continued)

RESIDENTIAL THERMOSTAT DIRECT INSTALLATION – NO NEW SERVICE

As of May 30, 2022, this delivery channel will be closed to new Customers. Existing Customers enrolled in the pilot through this channel will continue to be governed by the incentive and participation structure defined below until they have successfully participated in Direct Load Control events for five years, at which time, they will be eligible to receive seasonal incentives. Thermostat installations will be warrantied for one year.

This delivery channel allows Customers who own a qualifying Ducted Heat Pump, Electric Forced Air Heating, and/or Central Air Conditioner but do not own a Qualified Thermostat to participate by receiving one from the Company.

The Company will provide the following to Eligible Customers within the participation cap:

- For those Customers with a Ducted Heat Pump or Electric Forced Air, with or without Central Air Conditioner system, a connected thermostat that is installed, provisioned, and enrolled into PGE’s demand response platform at no additional charge; or

- For those Customers with a Central Air Conditioner, for a fee up to $150, a connected thermostat that is installed, provisioned, and enrolled into PGE’s demand response platform.

PGE may, at a later date, apply a mechanism to recover labor and materials costs if the Customer opts-out of more than 50% of the event hours in an Event Season or the Customer removes the enrolled thermostat. The Customer may be charged up to the following:

Participation Year Customer Opts-Out	Customer Payback of Thermostat Labor & Materials
1	100%
2	80%
3	60%
4	40%
5	20%
6	0%

If, a Customer returns the working qualified thermostat within 90 days of installation, they are not charged for the cost of the thermostat and are only charged for the labor associated with installing the thermostat.

SCHEDULE 5 (Continued)

DIRECT LOAD CONTROL EVENT

Direct Load Control Events occur for one to five hours. The Company may call two events per day but will not exceed five cumulative hours for the day. During Direct Load Control Events the Customer may allow the Company to control their thermostat for the duration of the event. The Customer has the option not to participate by overriding via the thermostat. The Company initiates Direct Load Control Events with Event Notification. The Company will call Direct Load Control Events only in the following months: December, January, February, June, July, August, and September. Direct Load Control Events will not be called on Holidays. 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. The Company will call no more than 150 event hours per Event Season.

SPECIAL CONDITIONS

1. The Customer may enroll at any time but must participate for the minimum number of hours described in the delivery channel section.

2. The Customer may notify PGE they wish to terminate enrollment in the pilot at any time. PGE will unenroll the customer from the program within approximately one week of the request. The Customer may be charged additional costs described in the participating Customers enrolled delivery channel section.

3. The Customer may opt-out of any Direct Load Control Event; however, if the Customer does not participate in at least 50% of Direct Load Control Events in an Event Season, the Customer may be charged additional costs described in the participating Customer's enrolled delivery channel section.

4. If a participating Customer is eligible for an incentive, it will be provided at the next billing statement after the event season ends.

5. The Company will defer and seek recovery of all pilot costs not otherwise included in rates.

6. The Company is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating Customer or third parties that result from AC Cycling or changing the thermostat set point.

7. The Company shall have the right to select the cycling schedule and the percentage of the Customer's heating or cooling systems to cycle at any one time, up to 100%, at its sole discretion.

SCHEDULE 5 (Concluded)

SPECIAL CONDITIONS (Continued)

8. The provisions of this schedule do not apply for any period that the Company interrupts the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular service associated with the Customer's Schedule 7 charges and associated charges.

9. PGE has the right to remove a Customer from the pilot when good cause is shown including, but not limited to, for poor customer responsiveness, consistent customer non-participation in called events, or issues with customer equipment that impact customer's participation.

PERTAINING TO BRING YOUR OWN THERMOSTAT

1. Customers that reenroll in the program are not eligible for a second payment for signing up. A Customer continuing service at a new residence is not considered a new enrollment.

2. If the participating Customer moves to a different residence, the Customer may continue participation if the new residence meets the eligibility requirements.

PERTAINING TO RESIDENTIAL THERMOSTAT DIRECT INSTALLATION

1. Customers in the residential thermostat direct installation delivery channel are excluded from receiving thermostat incentives by the Energy Trust.

2. Customers will be eligible for seasonal incentives after completion of five years of successful participation, as described in the delivery channel section, in Direct Load Control Events.

TERM

This pilot began December 1, 2015 and ends June 30, 2025.

SCHEDULE 7
RESIDENTIAL SERVICE

PURPOSE

This schedule provides Standard and Optional Service choices for residential customers. Optional Services include Time-of-Day (TOD) and Legacy Time-of-Use (TOU) portfolio options, Peak Time Rebate, and Green Future[SM] renewable portfolio options.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

ENERGY PRICE PLANS (DEFAULT PLAN, AND TOD AND LEGACY TOU PORTFOLIO OPTIONS)

RESIDENTIAL SERVICE PRICE PLAN (DEFAULT PLAN)

This default plan is provided to Residential Customers who have not chosen TOD or Legacy TOU portfolio option price plans.

Monthly Rate

The default plan is priced as the total of the following charges per Service Point (SP)*:

Basic Charge		
Single-Family Home	$13.00	
Multi-Family Home	$10.00	
Transmission and Related Services Charge	0.785	¢ per kWh
Distribution Charge	6.978	¢ per kWh
Energy Charge	8.161	¢ per kWh

* 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	$13.00	
Multi-Family Home	$10.00	
On-Peak Charge	39.430	¢ per kWh
Transmission and Related Services	2.380	¢ per kWh
Distribution	21.190	¢ per kWh
Energy	15.860	¢ per kWh
Mid-Peak Charge	15.400	¢ per kWh
Transmission and Related Services	0.690	¢ per kWh
Distribution	6.110	¢ per kWh
Energy	8.600	¢ per kWh
Off-Peak Charge	8.320	¢ per kWh
Transmission and Related Services	0.300	¢ per kWh
Distribution	2.640	¢ per kWh
Energy	5.380	¢ per kWh

* See Schedule 100 for applicable adjustments.

On- and Off-Peak Hours

On-Peak	4:00 p.m. to 9:00 p.m. Monday-Friday
Mid-Peak	7:00 a.m. to 4:00 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)

LEGACY TIME-OF-USE (TOU) PORTFOLIO OPTION

This optional price plan provides Legacy TOU 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 closed to new participants as of January 1, 2024. This portfolio option will expire for all participants after December 31, 2024, at which time any remaining participants will be placed on the Schedule 7 default plan.

Monthly Rate

Basic Charge		
Single-Family Home	$13.00	
Multi-Family Home	$10.00	
On-Peak Charge	26.939	
Transmission and Related Services	1.275	¢ per kWh
Distribution	11.334	¢ per kWh
Energy	14.330	¢ per kWh
Mid-Peak Charge	20.770	
Transmission and Related Services	1.275	¢ per kWh
Distribution	11.334	¢ per kWh
Energy	8.161	¢ per kWh
Off-Peak Charge	4.778	
Transmission and Related Services	0.000	¢ per kWh
Distribution	0.000	¢ per kWh
Energy	4.778	¢ per kWh

* See Schedule 100 for applicable adjustments.

SCHEDULE 7 (Continued)

LEGACY TIME-OF-USE (TOU) PORTFOLIO OPTION (Continued)

On- and Off-Peak Hours

Summer Months (begins May 1st of each year)

On-Peak	3:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	6:00 a.m. to 3:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and holidays

Winter Months (begins November 1st of each year)

On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	10:00 a.m. to 5:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. 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.

ENERGY PRICE PLANS: TOD and LEGACY TOU PORTFOLIO OPTIONS

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 TOD or Legacy TOU portfolio options) or as a separately metered service billed under TOD or Legacy TOU portfolio options. 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.

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: TOD and LEGACY TOU PORTFOLIO OPTIONS (Continued)

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 TOD and Legacy TOU Portfolio Options (including Whole Premise and EV Charging)

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 or Legacy TOU 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.

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 or Legacy TOU 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 or Legacy TOU 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.

6. The Company may recover lost revenue from the TOD or Legacy TOU optional price plan through Schedule 105.

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 or Legacy TOU option.

8. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons.

SCHEDULE 7 (Continued)

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. Holidays are 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.

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.

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.

SCHEDULE 7 (Continued)

ADDITIONAL PORTFOLIO OPTIONS FOR ENERGY PRICE PLANS (Continued)

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. Customers with interconnected energy storage are only eligible for this schedule if the energy storage system is controlled by the Company and not the Customer.

6. 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, renewable solar 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).

SCHEDULE 7 (Continued)

RENEWABLE FIXED OPTION

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

RENEWABLE SOLAR OPTION

PGE’s Renewable Solar Option will operate through December 31, 2022. Beginning on January 1, 2023, participants currently subscribed to the Renewable Solar Option will automatically transition to two blocks of the Renewable Fixed Option for every unit of the Renewable Solar Option.

The renewable solar option allows participating Customers, monthly, to support a PGE sponsored utility-scale solar power plant and its renewable attributes. The Company will purchase 1 kW of the output and RECs from new solar facilities connected to the Company’s electric grid per unit enrolled in renewable solar option.

SCHEDULE 7 (Continued)

GREEN FUTURE RENEWABLE PORTFOLIO OPTIONS (Continued)

In exchange for the Customer's payment of $5.00 per unit per month, the Customer receives the environmental attributes from a local utility-scale solar project and the utility-scale solar project produces 1 kW of Energy which flows into the grid. Typical purchases may range to the equivalent of a 1, 2 or 3 kW solar panel array. At the end of each year, the Company will provide individual results to the Customer, reporting how much the Customer's Energy usage was offset by solar power and the carbon footprint reduction benefit received. The RECs purchased by the Customer will be retired on behalf of the Customer.

Monthly Rate

Renewable Solar Option	$5.00	per unit in addition to Energy Charge

RENEWABLE HABITAT OPTION ADDER (HABITAT SUPPORT)

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 accounts that have been involuntarily disconnected in the last 12 months.

SCHEDULE 7 (Concluded)

Special Conditions Related to Green Future Renewable Portfolio Options (Continued)

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.

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.

SCHEDULE 8
RESIDENTIAL ELECTRIC VEHICLE CHARGING PILOT

PURPOSE

This Residential Electric Vehicle Charging Pilot (Pilot) is applicable to Residential Customers who own or lease an Electric Vehicle (EV). The Pilot offers rebates for the purchase, installation, and/or integration of technologies that help manage and increase the flexibility of load associated with residential EV Charging. The Pilot is expected to operate from October 23, 2020 to December 31, 2024.

AVAILABLE

In all territory served by the Company.

APPLICABLE

This Pilot is available to up to 5,000 eligible Residential Customers that elect to enroll and participate in the Pilot. Qualifying Customers will remain on Schedule 7 and be eligible for rebates and incentives described in this schedule.

DEFINITIONS

Active Charging Session – A period of time during which an EV is plugged into an EVSE for the purposes of having electricity supplied to the vehicle through the EVSE.

Direct Load Control – A remotely controllable communication device that allows the utility to operate an appliance/equipment, often by cycling.

Electric Vehicle Supply Equipment (EVSE) – The device, including the cable(s), coupler(s), and embedded software, installed for the purpose of transferring alternating current electricity at 208 or 240 volts between the electrical infrastructure and the EV.

Event Notification – The Company may issue a notification of a Managed Charging Event to participating Customers. Notification methods may include email, text, auto-dialer phone call, or via mobile app notification.

Holidays – The following are holidays for purposes of the Pilot: New Year's Day (January 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.

Income-Eligible Customer – A verified Residential Customer at 120% or below the state median income as defined by the US Department of Housing Urban Development, or the home qualifies for Section 8 housing.

SCHEDULE 8 (Continued)

DEFINITIONS (Continued)

Managed Charging Event – A period during which the utility will provide Direct Load Control by sending communication signals to a customer's vehicle or EVSE to adjust the rate or time of charge.

Participation Year – Twelve consecutive months from the anniversary date of a Qualifying Customer's enrollment in the Smart Charging Program.

Qualifying Customer – A Residential Customer in an existing single-family residence, including separately metered residences with assigned parking, with a Qualified L2 EVSE (excludes new construction or multifamily property).

Qualified Level 2 Electric Vehicle Supply Equipment (L2 EVSE) – A pre-approved L2 EVSE that meets the program's connectivity and controllability criteria.

Vehicle Telematics - Device installed in a vehicle that allows the sending, receiving, and storing of telemetry data.

ELIGIBILITY

Eligible Customers must comply with the terms of the participation agreement and be a Qualifying Customer with either of the following.

A. Qualified L2 EVSE and agree to the following minimum participation requirements:
   (1) the Qualified L2 EVSE is successfully connected to the Smart Charging Program for at least 50% of the participation year,
   (2) the Qualified L2 EVSE participates in six Managed Charging Events, and
   (3) the Qualified L2 EVSE completes 25 Active Charging Sessions.
   Or
B. EV with Vehicle Telematics connected to an approved vehicle telematics provider and agreement to the following minimum participation requirements:
   (1) the connected EV participates in six Managed Charging Events,
   (2) the connected EV completes 25 Active Charging Sessions, and
   (3) the vehicle telematics provider's participation agreement.

ENROLLMENT

Qualifying Customers can enroll in the Pilot at PortlandGeneral.com through July 31, 2024. Unless PGE terminates this Pilot, customers will remain enrolled in the Smart Charging Program for the entire Pilot term. Qualifying Customers that reenroll in the Pilot are not eligible for a second payment for installation of a single Qualified L2 EVSE. A Qualifying Customer continuing service at a new residence is not considered a new enrollment.

SCHEDULE 8 (Continued)

INCENTIVES

Qualifying Customers with more than one Qualifying L2 EVSE are eligible for the following incentives per each unique EV and EVSE pair during their participation in the Pilot:

Incentive	Description	Amount
Standard EVSE Installation Rebate	A one-time rebate for the purchase and installation of a Qualified L2 EVSE. PGE will automatically enroll Qualifying Customers into the Smart Charging Program. Qualifying Customers will receive the rebate by check or bill credit from the Company upon approval of rebate qualification.	Up to $500; capped at price paid
Income-Eligible EVSE Installation Rebate	A one-time rebate for Income-Eligible Qualifying Customers for the purchase and installation of a Qualified L2 EVSE. PGE will automatically enroll Qualifying Customers into the Smart Charging Program. Qualifying Income-Eligible Customers will receive the rebate by check or bill credit from the Company upon approval of rebate qualification.	Up to $1,000; capped at price paid
Bring Your Own Charger Rebate	A one-time rebate for Qualifying Customers with an existing Qualified L2 EVSE at a Qualifying Home, who enroll in the Smart Charging Program.	Up to $50
Vehicle Telematics Participation Incentive	A one-time incentive for the integration with a Vehicle Telematics provider. PGE will automatically enroll Qualifying Customers into the Smart Charging Program. Qualifying Vehicle Telematics Customers will receive the incentive by check or bill credit from the Company upon approval of rebate qualification.	Up to $150
Smart Charging Participation Incentive	For Qualifying Customers enrolled in the Smart Charging Program who participate in the minimum number of Managed Charging Events and Active Charging Sessions as described in this schedule. This incentive will be sent by check or as a bill credit within two billing cycles following the end of the interval period.	Up to $50 per participation year

SCHEDULE 8 (Continued)

INCENTIVES (Continued)

Smart Charging Program Reconnection Incentive	A one-time promotional incentive to encourage Qualifying Customers who unenrolled (intentionally or unintentionally) from the Smart Charging Program to re-enroll. This offer is available once per participant and at the discretion of the Company.	Up to $25
Standard Panel Upgrade Rebate	A one-time incentive to aid in the materials and electrical work necessary to upgrade participating customers' home electrical panels to 200A service in order to install a Qualified Level 2 EVSE. Customers must also be applying for a Standard EVSE Installation Rebate. Qualifying Customers will receive the rebate by check or bill credit from the Company upon approval of rebate qualification. This incentive is available until the designated Panel Upgrade Rebate funding is exhausted.	Up to $1,000; capped at price paid.
Income-Eligible Panel Upgrade Rebate	A one-time incentive to aid in the materials and electrical work necessary to upgrade participating customers' home electrical panels to 200A service in order to install a Qualified Level 2 EVSE. Customers must also be applying for an Income-Eligible EVSE Installation Rebate. Qualifying Income-Eligible Customers will receive the rebate by check or bill credit from the Company upon approval of rebate qualification. This incentive is available until the designated Panel Upgrade Rebate funding is exhausted.	Up to $5,000; capped at price paid.

MANAGED CHARGING EVENTS

Customers will be randomly assigned into one of three groups: A, B, or C. Group A will be the control group and will have no demand response tactics scheduled. Group B will participate in load shifting events where charging times will be shifted away from system peak periods. Group C will have their charging slowed or stopped during event periods. The Company will strive to maintain the equal number of participants and EVSE models in each group. Managed Charged Events may be called at any hour and any weekday excluding Holidays. During Managed Charging Events, the Customer will allow the Company to control their Qualified L2 EVSE or connected EV for the duration of the event. The Customer has the option not to participate by overriding via the manufacturer's mobile application.

SCHEDULE 8 (Concluded)

SPECIAL CONDITIONS

1. If a Qualifying Customer moves to a different residence, the customer may continue participation in the Smart Charing Program at the new residence if the Customer meets the eligibility requirements.

2. The Company will defer and seek recovery of all Pilot costs not otherwise included in rates.

3. The provisions of this schedule do not apply for any period that the Company interrupts the Qualifying Customer's load for a system emergency or any other time that a Qualifying Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular service associated with the Qualifying Customer's Schedule 7 charges and associated charges.

TERM

This pilot began October 23, 2020 and expires December 31, 2024.

SCHEDULE 13
SMART GRID TESTBED PILOT

PURPOSE

The Smart Grid Testbed Pilot (SGTB) is a first-of-its-kind research project meant to advance Portland General Electric's (PGE) collective understanding and development of demand response (DR) to gain insight into how PGE could provide a demand-side resource at scale in lieu of traditional supply-side resources. The second phase (Phase II) of the SGTB seeks to expand upon the research and planning conducted in Phase I, which concluded on December 31, 2022, to increase PGE's understanding of how customers perceive and value DR so that PGE may more effectively engage customers in flexible load efforts. All Phase I activities concluded December 31, 2022.

To achieve these goals, PGE is piloting both the Test Bed Smart Solar Study (Smart Solar Study) and Test Bed EV Charging Study (EV Charging Study) demonstration projects.

> Smart Solar Study: PGE will leverage customer owned "smart inverters" (those equipped with the IEEE 1547-2018 Standard) to assess the value of inverter-based controls to deliver distribution operations value (e.g., Volt/VAR support); address hosting capacity issues; and support orchestration of Distributed Energy Resources (DER) together with distributed solar and storage to minimize grid export. PGE will recruit customers with qualifying equipment by offering an upfront incentive in addition to an ongoing monthly incentive for continued enrollment throughout the project duration (January 2023 – December 2024).
>
> EV Charging Study: PGE will communicate with qualifying customer-owned electric vehicles (EV) to control the time of EV charging, while ensuring that the vehicles meet the operational needs of participants, and will evaluate customer acceptance of charge rate, charge time and Location-based Price Signals. Research in this project area will focus on improving understanding of the technical paths for charge management, costs, performance, and limitations. Customers within the EV Charging Study test bed with qualifying electric vehicles will opt in to receive an ongoing monthly incentive throughout the project duration (January 2023 – December 2024).

DEFINITIONS

IEEE 1547-2018 Standard – The standard that establishes the criteria and requirements for interconnection of distributed energy resources with electric power systems and associated interfaces.

Electric Vehicle Service Equipment (EVSE) - The device, including the cable(s), coupler(s), and embedded software, installed for the purpose of transferring alternating current electricity at 208 or 240 volts between the electrical infrastructure and the EV.

SCHEDULE 13 (Continued)

DEFINITIONS (Continued)

Location-based Price Signals – The notification that a specific utility rate is being offered to a customer determined by their location an eligible territory, allowing the utility to drive customer participation to achieve specific load shifting or load reduction goals of the area or feeder.

AVAILABLE

Each demonstration area will have a different and distinct project boundary based on research conducted in Phase I. PGE customers may be eligible to enroll in the SGTB demonstration projects if located within a testbed's geographic region as defined on PGE's Smart Grid Test Bed webpage.

Each SGTB Phase II demonstration project will have different and distinct applicability as is defined on PGE's Smart Grid Test Bed webpage. An overview of the customers eligible for the demonstration projects is as follows:

Smart Solar Study: Eligible Schedule 7 and Schedule 32 customers with interconnected photovoltaic (PV) systems behind the meter with qualifying smart inverters as defined on the SGTB webpage may elect to enroll in the project.

EV Charging Study: Eligible Schedule 7 customers with a qualifying EV as defined on the SGTB webpage and a Level 2 EVSE may elect to enroll in the project.

ENROLLMENT

Qualifying customers can enroll in the Smart Solar Study and EV Charging Study demonstration projects through the Smart Grid Test Bed webpage until December 31, 2024. Unless PGE terminates these demonstration projects, customers will remain enrolled for the entire project term. Each demonstration project within the SGTB Phase II will be subject to its own enrollment cap of a maximum of 500 participants for the Smart Solar Study and a maximum of 500 participants for the EV Charging Study.

INCENTIVES

Customers participating in a demonstration project within the SGTB will continue to pay all fees and charges associated with their currently enrolled rate schedule. Customers can qualify for the following incentives based on the demonstration project(s) enrolled:

Smart Solar Study: Eligible participants will receive a $250 incentive paid at time of enrollment and will receive an additional ongoing incentive of $10 per month while enrolled. The monthly incentive will begin at the month of enrollment after the tariff effective date and will continue through the end of the demonstration period (December 2024) unless the customer chooses to unenroll.

SCHEDULE 13 (Concluded)

INCENTIVES (Continued)

To remain enrolled in the project and to continue to receive monthly incentives, the customer must maintain the connection of their smart inverter to their WiFi network and must continue to allow PGE to communicate with their system via the manufacturer's interface.

EV Charging Study: Eligible participants will receive an incentive of $20 per month while enrolled. The monthly incentive will begin at the month of enrollment after the tariff effective date and will continue through the end of the demonstration period (December 2024) unless the customer chooses to unenroll. Customers must first enroll in Schedule 8 and remain enrolled in the EV Charging Study demonstration to continue to receive monthly incentives.

SPECIAL CONDITIONS

1. The Customer may unenroll from the Smart Grid Test Bed demonstrations at any time. If a Customer unenrolls, the Customer is not eligible to re-enroll during the pilot period.

2. At any time, PGE can interact with customer-owned equipment with intention to remotely adjust the device settings in accordance with project goals.

3. The participant will retain ownership of the PV system equipment and is responsible for all maintenance, replacement, and disposal costs.

4. Customers already enrolled in the Solar Payment Option are not eligible for the Smart Solar Study demonstration.

5. Incentives may be provided in an on-bill credit on the Customer's next monthly billing statement or by check issued by Energy Trust of Oregon.

6. PGE is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating Customer or third parties that result from performing direct load control on a participating appliance.

7. PGE shall have the right to select the schedule and the percentage of the Customer's appliance(s) to cycle at any one time, up to 100%, at its sole discretion.

8. PGE will defer and seek recovery of all pilot costs not otherwise included in customer prices.

TERM

Phase II of the Smart Grid Test Bed concludes on December 31, 2027. The Smart Solar Study and EV Charging Study pilots will conclude on December 31, 2024.

SCHEDULE 14
RESIDENTIAL BATTERY ENERGY STORAGE PILOT

PURPOSE

This residential battery energy storage pilot will evaluate the ability of residential batteries to deliver services in support of PGE's electrical system. The battery energy storage pilot offers incentives to allow the Company to manage the charging and discharging of customer batteries with the option for a customer override. The pilot is expected to be conducted from August 1, 2020 through July 31, 2025.

AVAILABLE

In all territory served by the Company.

APPLICABLE

This program is applicable to Residential (Schedule 7) Customers that own a qualifying battery[1] and elect to enroll and participate in the pilot. Customers will remain on Schedule 7 and will be eligible for the incentives described in this schedule. The pilot is optional and limited to 525 residential customers.

ELIGIBILTY

Customers must submit an interconnection application which must be approved by PGE, purchase or already own a qualifying battery, proceed with installation, and apply for acceptance into the pilot.

ENROLLMENT

Customers will be allowed to enroll in this pilot until the pilot reaches its maximum enrollment of 525 residential customers. Unless this pilot is otherwise terminated, participating Customers will be enrolled for the entire pilot term.

INCENTIVES

Basic Offering

1. Available to customers who have a qualifying battery and allow PGE to manage the charging and discharging of such equipment for the benefit of PGE's electric system.

2. For customers with a battery that is able to charge from the electrical grid, PGE will pay the customer $40 monthly for the duration of the pilot or until the customer disenrolls, whichever is earlier.

1. A list of approved qualifying battery storage systems for this pilot is available on PortlandGeneral.com

SCHEDULE 14 (Continued)

INCENTIVES (Continued)

3. For customers with a battery that is unable to charge from the electrical grid (restricted to charging with onsite solar only), PGE will pay the customer $20 monthly for the duration of the pilot or until the customer disenrolls, whichever is earlier.

Test Bed Rebate

1. Available only to customers who are served by the Delaware, Island, or Roseway substations, who purchase a new qualifying battery, and allow PGE to manage the charging and discharging of such equipment for the benefit of PGE's electric system.

2. In addition to the Basic Offering, PGE shall provide a rebate for the new purchase and installation of a qualifying battery storage system.

3. The new purchase rebate is limited to 200 customers. The rebate amount shall be $3,000 for the first 67 customers that have a pilot application approved by PGE, $2,000 for customers 68 through 134, and $1,000 for customers 135 through 200.

4. The rebate level will be reserved for a customer for nine months from when the pilot application is approved to when the battery storage system is operable by PGE and enrolled in this pilot. If the battery storage system does not begin communications with PGE within nine months of pilot application approval, the customer's reserved rebate will be released. When communications are established the customer may receive the incentive at the currently available level, if still available.

5. A developer or builder is eligible to receive the rebate if purchase and installation of a qualified battery storage system occurred prior to occupancy by a residential customer and enroll the battery in the Pilot.

Income Qualified Rebate

1. Available to customers receiving incentives from the Energy Trust of Oregon's Solar Within Reach program that purchase a new qualifying battery storage system and allow PGE to operate such equipment for the benefit of PGE's electric system.

2. In addition to the Basic Offering, PGE shall provide a rebate of $5,000 for the new purchase and installation of a qualified battery storage system. The rebate is limited to the first 25 customers.

SCHEDULE 14 (Continued)

SPECIAL CONDITIONS

1. Participants are responsible for any equipment, installation, and associated costs of the battery storage system, including any upgrades identified in the PGE interconnection process.

2. The participant will retain ownership of the battery storage system and is responsible for all maintenance, replacement, and disposal costs.

3. In the event of non-payment of electricity bill charges or disconnection for non-payment, for Electricity Service rendered, PGE will discontinue credit payments and battery storage system operation until the participant is current on all past-due balances. The participant will be removed from the pilot if basic service electricity charges are not current after two consecutive months.

4. The participant is required to maintain reliable communications with the battery storage system. If communications to the battery storage system are not restored in a timely manner PGE may discontinue paying the monthly incentive until communications are reestablished, or PGE may remove the customer from the pilot.

5. A participant that only receives the Basic Offering and did not receive a Test Bed or Income Qualified rebate may disenroll from the pilot at any time, upon which PGE will cease monthly payments.

6. If the participant has received a Test Bed or Income Qualified rebate, the customer may be required to repay the unamortized portion of the rebate in the event that the customer voluntarily disenrolls prior to the end of the pilot, or if the battery storage system is removed from the pilot due to lapses in communications. This is defined as the proportion of the months left until the end of the pilot divided by the months the customer has participated in the pilot.

7. Participants must agree to the contractual terms laid out in the Residential Battery Energy Storage Pilot contract.

8. PGE will have full control of the battery storage system for grid services that override any manufacturer programming.

9. PGE will never discharge the battery storage system below 20% of capacity or below the manufacturer's warranty recommendation, whichever is higher.

SCHEDULE 14 (Concluded)

SPECIAL CONDITIONS (Continued)

10. The participant may override PGE's control up to ten times per calendar year for a period of 24 hours per time.

11. During times of severe weather, defined as any time PGE has placed emergency operators on Standby status, PGE will allow the battery storage system to fully charge.

12. In the event of a power outage, the customer will have full use of the battery storage system until grid service is restored. Power outages are not considered a customer override.

13. Customers enrolled in Solar Payment Option may not participate in this Pilot offering.

14. A customer may only receive one rebate or bill credit per service meter.

TERM

This pilot began on August 1, 2020 and ends on July 31, 2025.

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	0.453	¢ per kWh
Distribution Charge	6.231	¢ per kWh
Cost of Service Energy Charge	6.047	¢ per kWh

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	$13.45(2)
	400	21,000	147	23.98(2)
	1,000	55,000	374	53.51(2)
HPS	70	6,300	30	9.90(2)
	100	9,500	43	10.68
	150	16,000	62	13.18
	200	22,000	79	15.87
	250	29,000	102	18.33
	310	37,000	124	22.03(2)
	400	50,000	163	26.32
Flood, HPS	100	9,500	43	10.57(2)
	200	22,000	79	15.79(2)
	250	29,000	102	20.37
	400	50,000	163	28.13
Shoebox, HPS (bronze color, flat	70	6,300	30	9.65
lens or drop lens, multi-volt)	100	9,500	43	11.90
	150	16,500	62	14.79
Special Acorn Type, HPS	100	9,500	43	16.77
HADCO Victorian, HPS	150	16,500	62	19.20
Early American Post-Top, HPS				
Black	100	9,500	43	12.27

(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	$15.25
	175	12,000	71	14.80
Flood, Metal Halide	350	30,000	139	26.34
	400	40,000	156	25.67
Flood, HPS	750	105,000	285	47.08
HADCO Independence, HPS	100	9,500	43	16.27
HADCO Techtra, HPS	100	9,500	43	23.45
	150	16,000	62	26.73

(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	$14.90
	>40-45	3,500	15	15.15
	>45-50	5,488	16	12.73
	>50-55	4,000	18	15.53
	>55-60	4,213	20	15.79
	>60-65	4,273	21	15.91
	>65-70	4,332	23	15.78
	>70-75	4,897	25	16.42
HADCO LED	70	5,120	24	20.40
Roadway LED	>20-25	3,000	8	6.11
	>25-30	3,470	9	6.24
	>30-35	2,530	11	6.86
	>35-40	4,245	13	6.75
	>40-45	5,020	15	7.18
	>45-50	3,162	16	7.35
	>50-55	3,757	18	7.88
	>55-60	4,845	20	7.82
	>60-65	4,700	21	7.94
	>65-70	5,050	23	8.92
	>70-75	7,640	25	9.19
	>75-80	8,935	26	9.32
	>80-85	9,582	28	9.57
	>85-90	10,230	30	9.83
	>90-95	9,928	32	10.08
	>95-100	11,719	33	10.21
	>100-110	7,444	36	10.81
	>110-120	12,340	39	10.98
	>120-130	13,270	43	11.48
	>130-140	14,200	46	12.82
	>140-150	15,250	50	14.67
	>150-160	16,300	53	15.05
	>160-170	17,300	56	15.43
	>170-180	18,300	60	15.86
	>180-190	19,850	63	16.32
	>190-200	21,400	67	16.71

(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)
Pendant LED (Non-Flare)	36	3,369	12	$16.53
	53	5,079	18	18.54
	69	6,661	24	19.05
	85	8,153	29	20.30
Pendant LED (Flare)	>35-40	3,369	13	16.25
	>40-45	3,797	15	16.50
	>45-50	4,438	16	16.63
	>50-55	5,079	18	19.70
	>55-60	5,475	20	19.96
	>60-65	6,068	21	20.08
	>65-70	6,661	23	19.43
	>70-75	7,034	25	19.68
	>75-80	7,594	26	20.04
	>80-85	8,153	28	20.29
CREE XSP LED	>20-25	2,529	8	6.26
	>30-35	4,025	11	6.64
	>40-45	3,819	15	7.15
	>45-50	4,373	16	7.28
	>55-60	5,863	20	7.85
	>65-70	9,175	23	8.75
	>90-95	8,747	32	9.89
	>130-140	18,700	46	13.12
Post-Top, American Revolution LED	>30-35	3,395	11	9.44
	>45-50	4,409	16	10.08
Flood LED	>80-85	10,530	28	10.85
	>120-130	16,932	43	13.31
	>180-190	23,797	63	17.09
	>370-380	48,020	127	29.74

(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	$6.42
	40 to 55	7.59
Wood, Painted for Underground	35 or less	6.36 (3)
Wood, Curved Laminated	30 or less	7.51 (3)
Aluminum, Regular	16	4.91
	25	9.14
	30	10.52
	35	12.22
Aluminum, Fluted Ornamental	14	8.74
Aluminum, Fluted Ornamental	16	9.08
Aluminum Davit	25	9.77
	30	11.02
	35	12.64
	40	16.25
Aluminum Double Davit	30	12.26
Aluminum, Smooth Techtra Ornamental	18	18.77

(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	$11.52
Fiberglass, Regular		
Black	20	5.31
Gray or Bronze	30	8.63
Black, Gray, or Bronze	35	8.46
Fiberglass, Anchor Base, Gray or Black	35	11.62
Fiberglass, Anchor Base (Color may vary)	25	10.26
	30	12.59
Fiberglass, Direct Bury with Shroud	18	7.17
Aluminum, Regular with Breakaway Base	35	17.60
Aluminum, Double-Arm, Smooth Ornamental	25	14.73
Aluminum, Smooth, Black, Pendant	23	17.96

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 15 (Concluded)

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Maintenance of outdoor area lighting poles includes replacement of accidentally or deliberately damaged poles and luminaires. If damage occurs more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will pay for future installations or may mutually agree with the Company and pay to have the pole either completely removed or relocated.

3. Electricity delivered to the Customer under this schedule may not be resold by the Customer.

4. If Company-owned area lighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer’s selection of service under this Schedule requires the removal of Company-owned area lighting equipment or poles.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 17
COMMUNITY SOLAR - OPTIONAL

PROGRAM DESCRIPTION

In accordance with Senate Bill (SB) 1547, Division 88 of Chapter 860 of the Oregon Administrative Rules (OARs), and Oregon Public Utility Commission (Commission) Order Nos. 18-177 and 19-392, the Oregon Community Solar Program (CSP or Program) is an optional program that will provide Participants the opportunity to share in the costs and benefits associated with community solar. The Program rules and Customer participation requirements are described in detail in the Program Implementation Manual (PIM).

AVAILABLE

In all territory served by the Company.

APPLICABLE

The CSP is applicable to Customers that meet the eligibility requirements set forth in OAR 860-088-0090 and described in the PIM.

DEFINITIONS

Annual Billing Period – Period beginning on the first day of the April billing month and running through the close of the March billing month, unless the Company and the Program Manager agree otherwise.

Community Solar Program, CSP or Program – The program for the procurement of electricity by electric companies from Projects.

Low-income Participant – Participant meeting the low-income requirement set forth in the PIM, as identified by the Project Manager and verified by the Low-income Facilitator.

Bill Credit - The Company will apply a credit to each Participant's monthly utility bill in accordance with the process and calculations set forth in ORS 757.386(6), OAR 860-088-0170, and the PIM. Bill Credits will be applied to offset utility charges and participation fees. The Program Administrator will calculate the value of a Bill Credit based on the Participant's share in the total Project generation multiplied by the Project's Bill Credit Rate.

Bill Credit Rate – The rate, in dollars per kilowatt-hour, at which the Company provides credits to a Participant for energy produced based on Participation Interest in a Project. The Commission assigns the Bill Credit Rate to each Project at the time of Project pre-certification. A Projects' Bill Credit Rate will remain fixed for the term of the CSP Purchase Agreement.

CSP Purchase Agreement – The power purchase agreement between the Company and Project Manager as described in Schedule 204.

SCHEDULE 17 (Continued)

DEFINITIONS (Continued)

Participant – A subscriber or owner as defined in OAR 860-088-0010(6) and (15).

Participation Interest – A Participant's proportional share of a Project based on capacity.

Program Administrator – A third-party directed by the Commission to administer the CSP. The Commission has selected Energy Solutions as the Program Administrator.

Program Implementation Manual or PIM – The set of guidelines and requirements for implementing the CSP adopted by the Commission. The PIM can be found on the Oregon Community Solar website at https://www.oregoncsp.org

Program Fees - Program Fees include both the Program Administrator fee and the Utility Fee to administer various aspects of the CSP. Program Fees are added to a Participant's monthly bill and are expressed in $/kW-AC per month. Low-Income Participants are exempt from Program Fees.

Project – One or more solar photovoltaic energy systems that provide Participants the opportunity to share the costs and benefits associated with the generation of electricity by solar photovoltaic energy systems in the CSP.

Project Manager – The entity identified as having the responsibility for managing the operation of a Project and, if applicable, for maintaining contact with the electric company that procures electricity from the Project, as defined in ORS 757.386(1)(d).

Service Territory – The geographic area approved by the Commission for the Company to serve Customers.

Subscription - A Customer's subscription or ownership of a portion of a Project. When Customers subscribe to a Project, they are subscribing to a portion of the Project's capacity in kilowatts (kW-AC).

Subscription Agreement - A contractual agreement between a Participant and a registered Project Manager to enroll in a Project.

Subscription Fee - The Subscription Fee is a charge by the Project Manager that may be listed on a Participant's utility bill, or may be off-bill, and reflects monthly cost to subscribe to the Project. On-bill Subscription models may be either capacity-based ($/kW) or production based ($/kWh).

Utility Fee – Fee that the Company collects on each Participant's utility bill to fund the Company's administration of the Community Solar Program, in accordance with OAR 860-088-0160(2).

SCHEDULE 17 (Continued)

CUSTOMER ELIGIBILITY

To be a Participant, Customers must meet the requirements set forth in OAR 860-088-0090 and described in Chapter 3 (Requirements) of the PIM, enroll in a Project that has been pre-certified by the Commission, and sign a Subscription Agreement with a registered Project Manager of the Project.

Detailed program eligibility details are provided in the PIM, Chapter 3, starting at page 48.

Eligible Customer types - A list of eligible customer rate schedules and their accompanying customer type classifications is available on the program website at https://www.oregoncsp.org. Direct access customers, lighting/traffic signals, cost of service opt-out customers, and customers who are receiving volumetric incentive rates (VIR) under the Solar Photovoltaic Volumetric Incentive Program are not eligible to participate.

COMMUNITY SOLAR ENERGY BILL CREDIT

1. Bill Credit Rate:
   The Commission establishes a Project's Bill Credit Rate at the time of Project pre-certification. The Commission has adopted Bill Credit Rates based on the capacity of pre-certified Projects to come online in PGE's Service Territory. The current Bill Credit Rate can be found on the Oregon Community Solar Website https://www.oregoncsp.org

2. Bill Crediting Rules:
   A Participant's monthly Bill Credit is calculated by multiplying the Bill Credit Rate by the Participant's share of total Project generation in that month. This will be a dollar value.

   The value of the monthly Bill Credit will be applied to the Participant's total Company bill (in dollars), less any other on-bill repayment expenses, respecting the Company's established bill crediting hierarchy. Information on the crediting hierarchy of the Company is available on the program website under Project Manager Resources, https://www.oregoncsp.org

   If the value of the monthly Bill Credit, minus any other on-bill repayment expenses, is greater than the total amount due on the Company's bill, an excess credit may appear. This excess credit may not be refunded, and will carry forward to subsequent months. If this excess credit is not consumed by monthly energy usage and charges by the end of the annual period, then, at the end of the annual period, PGE will donate the value of the amount carried forward to low income programs as required by the PIM.

3. Bill Credit Allowable Offsets:
   Bill Credits offset all Company charges and on-bill Subscription charges for Participant's electric bills. Bill Credits cannot offset non-Company charges, which may be collected on the Company bill, but are passed on to third parties, such as loans.

SCHEDULE 17 (Continued)

COMMUNITY SOLAR ENERGY BILL CREDIT (Continued)

If a Participant has multiple sites under one utility account, the Bill Credit will be applied separately to each site designated under the CSP. If a single site hosts multiple meters, the Bill Credit may offset the sum of all electric meters on the site.

4. Nonpayment and Underpayment:
In accordance with the PIM, the Company will recover any unpaid Participation or Program Fees on the Participant's next monthly utility bill. At the direction of the Program Administrator, the Company will suspend the application of Bill Credits or terminate a Participant's Participation Interest for failure to pay Participation and Program Fees in full.

5. Utility Disconnection:
If the Company disconnects a Participant's utility service temporarily, the Company will apply the Bill Credits, Participation Fees and Program Fees that accrue during the period of disconnection to the Participant's next monthly utility bill, in accordance with the PIM. Depending on the agreed terms between a Participant and the Project Manager, utility disconnection may result in the early termination of a Participant's Participation Interest by the Project Manager.

6. Timing:
In accordance with the PIM the Company will post a Participant's Bill Credit to their account on the ninth calendar day of each month, unless the ninth calendar day is a Sunday or holiday, in which case the Bill Credit will post on the following calendar day. If a Participant's billing period ends after the ninth calendar day of the month, their bill will reflect their Bill Credit for the previous month. If a Participant's billing period ends before or on the ninth calendar day of the month, their bill will reflect a one-month lag in the application of the Bill Credit.

7. Excess Credits:
If a Participant accrues Bill Credits that exceed the eligible expenses on their monthly utility bill, the excess Bill Credit amount will be carried forward and applied to the Participant's subsequent utility bills. In accordance with the PIM, a Participant may not cash out carryover Bill Credit amounts.

8. Annual Bill Credit Reconciliation:
Under OAR 860-088-0090(2) and OAR 860-088-0170(4), a Participant is not permitted to receive Bill Credits for more energy than they consume on an annual basis. If a Participant's Participation Interest in a Project generates more energy than their annual usage, the Company will apply a reconciliation charge to the Participant's next monthly bill based on calculations performed by the Program Administrator and in accordance with the process set forth in the PIM. A Participant's annual excess generation will be calculated based on the Participant's usage and their share of Project generation during the Annual Billing Period.

SCHEDULE 17 (Continued)

PROGRAM FEE

The Company will apply Program Fees, if applicable, to each Participant's utility bill based on Participants' Participation Interest. Program Fees will consist of a Program Administrator Fee and a Utility Fee. Program Fees may be subject to an annual adjustment, and are currently set at the following amounts:

Program Administrator Fee:	$0.85/kW/month
Utility Fee:	$0.11/kW/month
Program Fees (total)	$0.96/kW/month

Program Fees are subject to annual adjustments per the PIM Low-income Participants are exempt from Program Fees.

SUBSCRIPTION FEE

The Subscription Fee is a charge determined by the Project Manager that may be listed on a Participant's utility bill, or may be off-bill, and reflects monthly cost to subscribe to the CSP. Off-bill Subscriptions require Program Administrator approval as provided in PIM Chapter 3: Project Requirements.

SPECIAL CONDITIONS

1. A Participant's ownership interest in, or Subscription to, a Project may not exceed the retail electricity customer's average annual consumption of electricity in the Service Territory in which the Project is located.

2. Participant Interest may not exceed 40 percent interest in the Project.

3. With respect to Projects certified during the initial program capacity tiers:
   a. A Participant, and its affiliates, as defined in the PIM, may own or subscribe to no more than 4 MW-AC of capacity, in aggregate, across all participating utilities (i.e., PGE, PacifiCorp, and Idaho Power); and
   b. For the program interim capacity tier, a Participant may not own or subscribe to more than 2 MW-AC of capacity across all participating utilities.

4. These tariff terms apply to the Commission-approved initial capacity tier of the CSP. Any future program capacity tiers will be approved by the Commission and the Commission will then set participation requirements and the Bill Credit Rate.

5. SB 1547, Division 88 of Chapter 860 of the OARs, Commission Orders Nos. 18-177 and 19-392, and the PIM will govern to the extent this Schedule 17 may conflict with them.

SCHEDULE 17 (Concluded)

SPECIAL CONDITIONS (Continued)

6. Portability:
A Participant may retain their Participation Interest in a Project if they relocate to another site within the Company's Service Territory in accordance with the terms of the PIM and, if applicable, their agreement with the Project Manager.

7. Transferability:
A Participant may transfer their Participation Interest in a Project to another eligible customer of their choosing in accordance with the terms of the PIM and, if applicable, their agreement with the Project Manager. Any fees assessed by the Project Manager for the transferal of a Participant's Participation Interest will not be reflected on the Participant's utility bill. When a Participant transfers their Participation Interest to another customer, the Company will continue to apply any Excess Credit amounts to the Participant's utility bill.

If the Participant terminates utility service with the Company, the Company will donate any Excess Credit amounts associated with the Participant's Participation Interest to the Company's low-income program.

8. Changes:
A Participant may change the size of their Participation Interest in accordance with the terms of the PIM and, if applicable, their agreement with the Project Manager. Any fees assessed by the Project Manager to change the size of a Participant's Participation Interest will not be reflected on the Participant's utility bill. Low Income Participants are not subject to change fees.

9. Early Termination:
A Participant or a Project Manager may terminate a Participant's Participation Interest before the end of their contract term, in accordance with the terms of the PIM, and, if applicable, their agreement with the Project Manager. Any early termination fees assessed by the Project Manager will not be reflected on the Participant's utility bill. When a Participant or Project Manager terminates a Participant's Participation Interest, the Company will donate any Excess Credit amounts associated with the Participant's Participation Interest to the Company's low-income program in accordance with the process described in the PIM.

10. Completion:
A Participant's Participation Interest is complete when the Company applies the final Bill Credit amounts to the Participant's monthly utility bill and the Company completes the final Annual Bill Credit Reconciliation.

11. Term:
This Schedule will apply for the term agreed to between a Participant and the Project Manager, not to extend beyond the end date of the Annual Billing Period following the termination of the Project Manager's CSP Purchase Agreement.

SCHEDULE 18
INCOME-QUALIFIED BILL DISCOUNT - OPTIONAL

PROGRAM DESCRIPTION

This is an optional bill discount for Income-Qualified Residential customers.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Income-Qualified Residential Customers, defined as Customers with gross household income at or below 60% of Oregon State Median Income (SMI), adjusted for household size. For Customers in single-person households, eligibility is extended to those with gross household incomes up to the greater of 60% SMI or $30,700.

MONTHLY DISCOUNT

Monthly bill discounts are calculated as a percentage of bill and are offered at three levels, based on the enrolled Customer’s household income as a percentage of SMI. Tier 1 Customers with household incomes up to 30% of SMI will receive a 25% discount on their electricity bill; those in Tier 2 with household incomes between 31% and 45% of SMI will receive a 20% discount; and those in Tier 3 with household incomes between 46% and 60% of SMI (and single-person households up to $30,700) will receive a 15% discount.

Enrolled Customers with a verified Emergency Medical Certificate on their PGE account will be moved to the next highest discount level, if not already qualified for the highest discount level (25%).

The bill discount applies to most components of a Customer’s bill, with a small number of charges not subject to the discount. Excluded charges include the following, where applicable:

- Green Future Solar, Fixed and Habitat Optional Charges
- Solar Customer Charge for Customers on Solar Payment Option
- Energy Efficiency Funding Adjustment (Schedule 109)
- Low Income Assistance Charge (Schedule 115)
- Meter Rental and Non-Network Meter Read Charges (Schedule 300)

SPECIAL CONDITIONS

1. Program participants must be the accountholder.

2. Household size reflects all permanent residents in the home, including adults and children.

SCHEDULE 18 (Concluded)

SPECIAL CONDITIONS (Continued)

3. Qualifying income refers to total gross annual income, both taxable and nontaxable, from all sources for all persons in the applicant’s household.

4. The discount applies only to bills associated with the Customer’s permanent primary residence and only to new charges billed after enrollment.

5. PGE Customers who have qualified for the federal Low-Income Home Energy Assistance Program (LIHEAP) or the Oregon Energy Assistance Program (OEAP) will be automatically enrolled in Tier 3. Those who also have a verified Emergency Medical Certificate on their PGE account will automatically be enrolled in Tier 2. Automatically enrolled Customers who believe they qualify for a larger discount are encouraged to submit an application and upon approval, will be moved to the appropriate tier. Should PGE be provided with detailed Customer eligibility information, automatically enrolled Customers will be placed directly in the appropriate tier. Customers who do not wish to receive the discount can contact PGE to be unenrolled.

6. Customers not otherwise automatically enrolled may participate in the program after the approval of an application that includes a declaration of household size and income. Applications can be submitted directly by the Customer or a third-party on behalf of the Customer. Re-enrollment will be required every two years.

7. Annually, beginning April 2023, PGE will require post-enrollment verification of need from a randomly selected 3% of enrolled Customers to continue receiving this discount. If a Customer’s discount is discontinued due to non-responsiveness or ineligibility, they may re-enroll upon providing verification of eligibility. Customers who were automatically enrolled based on LIHEAP or OEAP eligibility are exempt from post-enrollment verification.

SCHEDULE 25
NONRESIDENTIAL DIRECT LOAD CONTROL PILOT

PURPOSE

This Direct Load Control Pilot is a demand response option for eligible nonresidential Customers. The Direct Load Control Pilot offers incentives to allow the Company to control thermostats during Direct Load Control Events while providing a customer override. The Company provides advance notice to participating Nonresidential Customers for Direct Load Control Events. The Pilot is expected to be conducted from December 1, 2017 through May 31,2025.

DEFINITIONS

Central Air Conditioning – Air conditioner tied into a central ducted forced air system.

Direct Installation – Thermostat delivery model in which a PGE technician, or implementation contractor technician representing PGE, installs thermostat(s) at a qualifying customer Site at a reduced cost to the Customer and enables the thermostat(s) to participate in the Pilot.

Direct Load Control – A remotely controllable switch that allows the utility to operate an appliance, often by cycling. In terms of this pilot, direct load control allows the Company to change the set point or cycle the Nonresidential Customer's heating or cooling through the Customer's Qualified Thermostat in order to reduce the Customer's energy demand.

Direct Load Control Event – A period of time in which the Company will provide direct load control.

Ducted Heat Pump – Heat pump heating and cooling system hooked into a central ducted forced air system.

Electric Forced Air Heating – An electrical resistance heating system tied into a central ducted forced air system.

Event Notification – The Company will issue a notification of a Direct Load Control Event to participating Customers. Participating Nonresidential Customers must choose at least one method for receipt of notification. Notification methods may include email, text, auto-dialer phone call, on thermostat display screen, or via mobile app notification. Notification may also be available on the Company's website.

Event Season – The pilot has two event seasons: the Summer Event Season and the Winter Event Season.

Holidays – The following are holidays for purposes of the pilot: New Year's Day (January 1), Martin Luther King Day (third Monday in January), President's Day (third Monday in February), 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.

SCHEDULE 25 (Continued)

DEFINITIONS (Continued)

Non-Ducted HVAC System Thermostat Demonstration – A demonstration within the smart grid test bed that meets Special Conditions 8 through 10. Demonstations are limited in scope and will not interfere with the operations of the Nonresidential DLC Pilot.

Summer Event Season – Includes the successive calendar months June through September.

Winter Event Season – Includes the successive calendar months November through February.

Qualified Site – Nonresidential Customer building served under qualifying PGE rate Schedule (as defined in Applicable section below) with a unique PGE service address and utility meter. Additionally, Qualified Sites meet HVAC system requirements defined in Eligibility section below.

Qualified Thermostat – Thermostats that are Company-approved have been integrated with Company's demand response management system for event calling.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Nonresidential Customers served under Schedules 32, 38, 47, 49, 75, 83, 85, 89, and 90. The Company will limit participation to 7,000 Qualified Thermostats. Nonresidential Customers will remain on their base schedule and will be eligible for the incentives described in this schedule.

ELIGIBILITY

Eligible Nonresidential Customers must have a Network Meter. Nonresidential Customers must have a Qualified Thermostat connected to the internet and the heating or cooling system at their expense, except as provided in the Incentives section of this schedule. To participate in the Winter Event Season, the Nonresidential Customer must have a Ducted Heat Pump or Electric Forced Air Heating. To participate in the Summer Event Season, the Nonresidential Customer must have Central Air Conditioning or a Ducted Heat Pump.

SCHEDULE 25 (Continued)

DIRECT LOAD CONTROL EVENT

Direct Load Control Events occur for one to five hours. The Company may call two events per day but will not exceed five cumulative hours for the day. During Direct Load Control Events the Customer may allow the Company to control their thermostat for the duration of the event. The Customer has the option not to participate by overriding the temperature setpoint via the thermostat. The Company initiates Direct Load Control Events with Event Notification. The Company will call Direct Load Control Events only during the Event Seasons. Direct Load Control Events will not be called on weekends or Holidays. 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. The Company will call no more than 150 event hours per Event Season.

ENROLLMENT

The Customer may enroll at any time but must participate for the minimum number of hours described in the incentive section.

INCENTIVE

Participating Customers receive a Qualified Thermostat for signing up for the Direct Load Control Pilot's Direct Installation channel. A Customer may receive multiple Qualified Thermostats for separate spaces subject to verification by the Company. A Customer co-pay of up to $60 per installed thermostat is required for participation. Customers receive up to $60 per Qualified Site for each Event Season they participate. A Customer participating in all Event Seasons receives up to $120 per Qualified Site per Pilot year. Incentives are paid to the Customer with an automated clearing house (ACH,) check, bill credit, or generic gift card. To receive payment for an Event Season, all Qualifying Thermostats at the Qualified Site must participate in at least 50% of the event hours for which the Customer is eligible to participate in that Event Season.

SPECIAL CONDITIONS

1. Customers that reenroll in the program are not eligible for additional Qualified Thermostats for signing up. A Customer continuing service at a new location is not considered a new enrollment.

2. If the participating Customer moves to a different location, the Customer may continue participation if the new location meets the eligibility requirements.

3. The Company will defer and seek recovery of all pilot costs not otherwise included in rates.

4. The Company is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating Customer or third parties that result from Air Conditioning Cycling or changing the thermostat set point.

SCHEDULE 25 (Concluded)

SPECIAL CONDITIONS (Continued)

5. The Company shall have the right to select the cycling schedule and the percentage of the Customer's heating or cooling systems to cycle at any one time, up to 100%, at its sole discretion.

6. The Company shall have the right to pre-heat or pre-cool the Site as part of the Direct Load Control event in order to thermally condition the space to increase occupant comfort and site performance for the duration of the event.

7. The provisions of this schedule do not apply for any period that the Company interrupts the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular service schedule and associated charges and Customers will not be charged for energy not used or demand not set during Direct Load Control Events.

8. The Company may engage with Customers who have existing qualified thermostats installed at their Sites to enroll them in the pilot. Customers with pre-existing thermostats that were not installed through the Direct Installation channel are eligible for seasonal incentives.

9. PGE has the right to remove a Customer from the pilot when good cause is shown including, but not limited to, poor customer responsiveness, consistent customer non-participation in called events, or issues with customer equipment that impact customer's participation.

TERM

This pilot term is December 1, 2017 through May 31, 2025.

SCHEDULE 26
NONRESIDENTIAL DEMAND RESPONSE PROGRAM

PURPOSE

This schedule is an optional supplemental service that provides participating Large Nonresidential Customers incentives for providing utility grid services when called for by the Company. Under this schedule, the Customer provides a Committed Load Reduction that the Company calls at any time according to the conditions detailed below. The Customer may also elect to receive incentives for providing other grid services from qualifying resources, as described below.

DEFINITIONS

Baseline Load Profile – The average hourly load of the five highest load days in the last ten Typical Operational Days for the Winter Event Season or Summer Event Season.

Commissioning Test – An optional test event conducted by the Customer upon initial program enrollment that confirms the Customer's load reduction potential results in the anticipated amount of load (kW) curtailment.

Committed Load Reduction – A Customer nomination of load that represents the anticipated amount of load (kW) curtailed during an event.

Contingency Reserve Event – A Load Reduction Event that is called by PGE with no advance notice in response to a critical need for power in the region. These events can occur at any time of year and at any time of day, including Holidays and weekends.

Energy Payment – The payment made by the Company to the Customer, as determined by the Mid-Columbia Electricity Index (Mid-C) as reported by Powerdex, adjusted for losses based on the Customer's delivery voltage. The Energy Payment may be up to 120% of the Committed Load Reduction amount.

Firm Load Reduction – The difference between the Baseline Load Profile and the Customer's measured hourly energy usage during the Load Reduction Event or the Measured Energy Output during the Load Reduction Event.

SCHEDULE 26 (Continued)

DEFINITIONS (Continued)

Firm Load Reduction Options – Elections that determine the Customer's incentive levels; which include the maximum event hours per season option, the Notification Option, and the event windows (time period for an event) for which they want to participate.

Frequency Response Event – An immediate reduction of site load or dispatch of energy at maximum power for a short duration by a Non-Emitting Firm Capacity Resource in response to a disruption that causes the frequency of the electrical system to deviate from a nominal 60 hertz (Hz). These can occur at any time of year and at any time of day, including Holidays and weekends.

Grid Support - Frequency Response Events and Contingency Reserve Events are the two Grid Support functions that a Non-Emitting Firm Capacity Resource may elect to participate in. Grid Support functions will be dispatched with no advance notice in response to a disruption in the electrical grid or a critical need for power in the region.

Holidays – The following are holidays for purposes of this schedule: New Year's Day (January 1), Martin Luther King Day (third Monday in January), President's Day (third Monday in February), 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.

Load Reduction Event – An event that is called during the Winter Event Season or the Summer Event Season, where customer incentives are offered in exchange for a Committed Load Reduction.

Load Reduction Plan – Document of record that defines the Committed Load Reduction, Firm Load Reduction Options, Customer payments based on Qualified Load Reductions during a Load Reduction Event, terms of any Grid Support in which the Customer has agreed to participate in, and participation instructions for each enrolled location.

Measured Energy Output – An alternative measurement to using a Baseline Load Profile to determine a customer's Firm Load Reduction. Available for resources with their own metrology that can be made available to PGE for remote reading.

Non-Emitting Firm Capacity Resource – A continuously available electrical load or continuously available energy storage resource that can be dispatched with no notice and respond to a PGE signal within five seconds to provide Grid Support. This cannot be a resource identified in Special Condition 1.

SCHEDULE 26 (Continued)

DEFINITIONS (Continued)

Nonresidential Demand Response Program Agreement – An agreement between the Company and Customer that defines the enrollment terms by which each party agrees to participate.

Notification Option – The notification period in which the Company will alert the Customer prior to a Load Reduction Event; options include 18 hours, 4 hours, 10 minutes, and no notice.

Participation Month – The current calendar month during a Winter Event Season or the Summer Event Season.

Qualified Load Reduction – The average load reduction percentage for all Load Reduction Event hours during the Participation Month must be 70% of the Committed Load Reduction or greater to be qualified.

Reservation Payment – The payment made by the Company to the Customer, where the Customer's Qualified Load Reduction (kW) is multiplied by the sum of each applicable reservation price ($/kW) based on the options selected by the Customer adjusted for losses based on the Customer's delivery voltage.

Summer Event Season – Includes the successive calendar months June through September.

Typical Operational Days – Represents the 10 applicable days closest to the Load Reduction Event.

Winter Event Season – Includes the successive calendar months November through February.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Nonresidential Customers served under Schedules 32, 38, 47, 49, 75, 83, 85, 89, and 90. Participating Nonresidential Customers must execute a Nonresidential Demand Response Program Agreement to participate in this program.

SCHEDULE 26 (Continued)

CUSTOMER ENROLLMENT

Customers must be fully enrolled at least five business days prior to the Participation Month.

At the time of enrollment, the Customer chooses the Firm Load Reduction Options, which includes the Firm Load Reduction Option, Grid Support Option, the maximum event hours per season, the Notification Option, and the event windows (time period for an event) for which they want to participate. Customer elections are documented in the Load Reduction Plan. All options must be agreed to by the Customer and the Company. First-time participants can also opt-in for a Commissioning Test.

Customers wishing to opt into no notice dispatch or Grid Support with a Non-Emitting Firm Capacity Resource must utilize equipment or facilities that are directly dispatchable by PGE.

Within five business days of enrollment, or for Customers completing a Commissioning Test, within five days following the completion of such Commissioning Test, the Company will confirm receipt of the Service Point ID (SPID) the Customer intends to enroll under this schedule and the Company or its representatives will send a signed Agreement to the Customer's representative. The Customer may choose to aggregate SPIDs.

Upon completion of the initial term each Agreement will automatically renew for successive annual terms on January 1st of subsequent calendar years unless the Customer elects to terminate such Agreement by notifying PGE prior to January 1st or this Schedule is withdrawn, revoked or otherwise terminated.

CUSTOMER PARTICIPATION OPTIONS

Customers are offered three Firm Load Reduction Options for the contracted program year: Option 1, the Customer participates for both event seasons; Option 2, the Customer participates in only the Summer Event Season; and Option 3, the Customer participates in only the Winter Event Season.

Customer Option	Participation Months	Event Seasons
1	Nov, Dec, Jan, Feb, Jun, Jul, Aug, Sep	Both event seasons
2	Jun, Jul, Aug, Sep	Summer Event Season only
3	Nov, Dec, Jan, Feb	Winter Event Season only

FIRM LOAD REDUCTION OPTIONS

Several Firm Load Reduction Options are available to Customers in the reservation price section of this schedule. Options include differing maximum event hours per season, Notification Options, and event windows.

SCHEDULE 26 (Continued)

RESERVATION PRICE

20 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Option			
	18 hours	**4 hours**	**10 minutes**	**No Notice**
Summer (June – September)				
11 am – 4 pm	$1.68	$1.80	$1.91	$2.00
4 pm – 8 pm	$1.95	$2.08	$2.22	$2.32
8 pm – 10 pm	$0.39	$0.42	$0.45	$0.47
All summer windows	$4.02	$4.30	$4.57	$4.78
Winter (November – February)				
7 am – 11 am	$1.27	$1.35	$1.44	$1.51
11 am -4 pm	$0.73	$0.78	$0.83	$0.87
4 pm – 8 pm	$2.07	$2.22	$2.36	$2.47
8 pm – 10 pm	$0.73	$0.78	$0.83	$0.87
All winter windows	$4.80	$5.13	$5.46	$5.71

40 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Option			
Windows	**18 hours**	**4 hours**	**10 minutes**	**No Notice**
Summer (June – September)				
11 am – 4 pm	$2.52	$2.69	$2.87	$3.00
4 pm – 8 pm	$2.92	$3.12	$3.32	$3.47
8 pm – 10 pm	$0.59	$0.63	$0.67	$0.70
All summer windows	$6.04	$6.45	$6.86	$7.17
Winter (November – February)				
7 am – 11 am	$1.90	$2.03	$2.16	$2.26
11 am – 4 pm	$1.09	$1.17	$1.24	$1.30
4 pm – 8 pm	$3.11	$3.32	$3.54	$3.70
8 pm – 10 pm	$1.09	$1.17	$1.24	$1.30
All winter windows	$7.20	$7.70	$8.19	$8.56

SCHEDULE 26 (Continued)

RESERVATION PRICE (Continued)

80 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Option			
	18 hours	**4 hours**	**10 minutes**	**No Notice**
Summer (June – September)				
11 am – 4 pm	$3.35	$3.58	$3.81	$3.98
4 pm – 8 pm	$3.89	$4.16	$4.42	$4.62
8 pm – 10 pm	$0.79	$0.84	$0.89	$0.93
All summer windows	$8.03	$8.58	$9.12	$9.53
Winter (November – February)				
7 am – 11 am	$2.53	$2.70	$2.87	$3.00
11 am - 4 pm	$1.46	$1.56	$1.65	$1.72
4 pm - 8 pm	$4.14	$4.42	$4.70	$4.91
8 pm - 10 pm	$1.46	$1.56	$1.65	$1.72
All winter windows	$9.58	$10.23	$10.89	$11.36

COMMITTED LOAD REDUCTION

If a Customer has completed a test event, but not participated in actual events, their Committed Load Reduction will be based on committed load identified in the Load Reduction Plan. If Customer has completed only one event, their Committed Load Reduction will be the higher of either their committed load or their first event performance. If Customer has participated in more than one event, their Committed Load Reduction will be based on an average of actual load reductions during event hours. The Customer, at its discretion, may choose to increase its nomination above the levels described above.

QUALIFIED LOAD REDUCTION

If no events are called in a Participation Month, the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction.

In order to qualify for the full Reservation Payment during a month with Load Reduction Events, the Customer must provide a minimum of 90% of the Committed Load Reduction on average over each event for which the Customer is enrolled during events in that month. If the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction.

SCHEDULE 26 (Continued)

QUALIFIED LOAD REDUCTION (Continued)

To qualify for a proportional Reservation Payment during a month with Load Reduction Events, the Customer must deliver a minimum of 70% of the Committed Load Reduction on average over each Load Reduction Event for which the Customer is enrolled in that month. If the Customer qualifies for a reduced Reservation Payment; the Qualified Load Reduction is the average load reduction percentage for all Load Reduction Event hours during that month.

If the Customer fails to deliver a minimum of 70% of the Committed Load Reduction on average during any single event for which the Customer is enrolled during events in that month, the Customer is not eligible for the Energy Payment for that Load Reduction Event nor the Reservation Payment for that month. If other Load Reduction Events are called in the same month, and the Customer delivers a minimum of 70% of the Committed Load Reduction during such events, the corresponding Energy Reduction Payments are paid for each Load Reduction Event that the Customer delivers a minimum of 70% of the Committed Load Reduction on average over each event for which the Customer is enrolled during events in that month.

RESERVATION PAYMENTS

The Reservation Payment is the Qualified Load Reduction (kW) multiplied by the sum of each applicable Reservation Price ($/kW) based on the Firm Load Reduction Options selected by the Customer adjusted for losses based on the Customer's delivery voltage. For each event window (time period for an event) per season, only one price is applicable. The Reservation Payment is made to the Customer no later than 60 days after the month in which they participated.

Customers meeting PGE's eligibility criteria as defined in a separate policy document and incorporated into the Agreement may be eligible to receive at the time of commissioning the net present value of any Reservation Payments and Grid Support options elected in the Load Reduction Plan for the duration of the Agreement with PGE. If a Customer fails to deliver a minimum of 70% of the Committed Load Reduction on average over each event during a month for which the Customer is enrolled, the Customer must reimburse PGE the Reservation Payment for that month.

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* PGE will not call Load Reduction Events on Holidays. If a Holiday falls on Saturday, Friday is designated a Holiday. If a Holiday falls on Sunday, the following Monday is designated a Holiday. Grid Support events are in response to a grid emergency and may occur at any day or time, including Holidays.

SCHEDULE 26 (Continued)

ENERGY PAYMENTS

The Energy Payment is equal to the Mid-Columbia Electricity Index (Mid-C) as reported by the Powerdex, adjusted for losses based on the Customer's delivery voltage. The Firm Energy Reduction amount can be up to 120% of the Committed Load Reduction.

The monthly energy prices (per MWh) for the months in which the events are called* are:

Jan 2023	Feb 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Nov 2023	Dec 2023
$122.50	$105.00	$62.50	$175.20	$228.40	$186.80	$97.40	$111.20

The Energy Payment rates will be updated by December 1st for the next year beginning in January. Assessment and settlement of the Energy Payment will occur within 60 days of the Firm Load Reduction Event. Energy Payments are not eligible to be paid up-front at the time of commissioning.

LINE LOSSES

Losses will be included by multiplying the applicable price by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

LOAD REDUCTION MEASUREMENT

Load reduction is measured as a reduction of load from a customer baseline load calculation during each hour of the Load Reduction Event. Although the Load Reduction Plan shall specify the customer baseline load calculation methodology to be used, PGE generally uses the following baseline methodology:

Baseline Load Profile

The Baseline Load Profile is based upon the average hourly load of the five highest load days in the last ten Typical Operational Days for the event season period. For Customers choosing the four-hour or 10-minute notification options there is an adjustment to the amounts above to reflect the day-of operational characteristics leading up to the Firm Load Reduction Event if the Firm Load Reduction Event starts at 11 am or later. This adjustment is the difference between the Firm Load Reduction Event day load and the average load of the five highest days used in the Baseline Load Profile during the two-hour period ending four hours prior to the start of the Firm Load Reduction Event.

SCHEDULE 26 (Continued)

LOAD REDUCTION MEASUREMENT (Continued)

Measured Energy Output

For Firm Load Reduction provided by a resource that can be measured with its own metrology, load baselining is not required. Customers using devices with Measured Energy Output who opt out of a Baseline Load Profile must utilize equipment or facilities that are directly dispatchable by PGE so the Company can view the measured Firm Load Reduction.

Typical Operational Days

Typical Operational Days exclude days that a Customer has participated in a Load Reduction Event or pre-scheduled opt-out days as defined in the Special Conditions. Typical Operational Days for the Baseline Load Profile calculation are defined as the ten applicable days closest to the Load Reduction Event. Typical Operational Days may include or exclude Saturdays, Sundays and Western Electricity Coordinating Council (WECC) holidays. Grid Support events may occur at any day or time.

The Company may decline the Customer's enrollment application if the Company determines the Customer's energy usage is highly variable and the Company is not able to verify that a reduction will be made when called upon.

LOAD REDUCTION EVENT

The Company, at its discretion, initiates a Load Reduction Event by providing the participating Customer with the appropriate notification consistent with the Customer's selected Firm Load Reduction Option. The Customer reduces its load served by the Company, for each hour of the Load Reduction Event to achieve its Committed Load Reduction. Each Load Reduction Event will last from one to five hours in duration and the Company will call at least one event per season.

The Company initiates Load Reduction Events during the Winter Event Season and Summer Event Season.

GRID SUPPORT EVENTS

A Non-Emitting Firm Capacity Resource may elect to participate in Grid Support Events only, or in addition to, participating in Firm Load Reduction. A qualified resource for Grid Support must be available year-round and capable of responding to a signal from the Company with no advance notice within five seconds. The resource must be integrated with the Company's dispatch software.

SCHEDULE 26 (Continued)

GRID SUPPORT EVENTS (Continued)

Grid Support includes Frequency Response Events and Contingency Reserve Events, and are only dispatched in response to a grid disturbance or critical need for power in the region. Participating Customers will be compensated $29.38 per year per committed kW as a Reservation Payment. In addition, Energy Payments for load reduction will be paid to Customer for each Contingency Reserve Event. Due to the short duration of Frequency Response Events (less than 15 minutes), Energy Payments will not be paid to Customer if dispatched.

EVENT NOTIFICATION

The Company notifies the participating Customer of a Load Reduction Event using a mutually agreed upon method at the time of enrollment. The Company's notification includes a time and date by which the Customer must reduce the committed load for each period of the Load Reduction Event. Customers enrolled in the "No Notice" option for Firm Load Reduction will still receive notification for events that are pre-planned. No Event Notification is required for Grid Support Events.

The Customer is responsible to notify the Company if the Customer's contact information specified at the time of the enrollment changes as soon as such change occurs.

SPECIAL CONDITIONS

1. Customers cannot use on-site diesel, pipeline natural gas or propane or other carbon emitting generation equipment for load reductions to meet load reduction commitments under this schedule.

2. Customers that choose to take service under Schedules 86, 485, 489, 490, 532, 538, 549, 575, 583, 585, 589, 590, or 689 will be withdrawn from this program.

3. Firm Load Reduction by Schedule 75 Customers will not exceed the Customer's baseline load as specified in the Agreement between the Customer and the Company. Customer cannot use purchases under Schedule 76R to meet load reduction commitments under this schedule.

4. In the case of Customers participating on Schedule 76R – Partial Requirements Economic Replacement Power Rider – at the time of the event, the energy imbalance will not apply during event hours and for the event energy amount.

5. This schedule is not applicable when the Company requests or initiates Load Reduction affecting a Customer SPID under system emergency conditions described in Rule N or Rule C(2)(B).

SCHEDULE 26 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Company will not cancel or shorten the duration of a Firm Load Reduction Event once notification has been provided.

7. Participating Customers are required to have interval metering and meter communication in place prior to participation in this schedule. The Company will provide and install necessary equipment which allows the Company and the Customer to monitor the Customer's energy usage.

8. If the Customer experiences operational changes or a service disconnection that impairs the ability of the Customer to provide the Firm Load Reduction as requested under this schedule, the Agreement will be terminated.

9. If the Company is not allowed to recover any costs of this program by the Commission, the Company may, at its option, and with 30-day notice, end service under this Schedule and terminate the Agreement.

10. The Customer may pre-schedule four opt-out days per season as indicated in the Agreement. If the Company calls a Firm Load Reduction Event on a pre-scheduled opt-out day, the Customer is exempt from providing Firm Load Reduction and will receive no Energy Payment, whether or not they choose to operate. The Customer will receive the Reservation Payment if otherwise eligible. An opt-out day will not be included in the calculation of the Baseline Load Profile.

11. Customers who participate in this schedule may be placed on a calendar monthly billing cycle.

12. Inverter based Non-Emitting Firm Capacity Resources must be IEEE 1547-2018 compliant, built and installed in compliance with UL 1741SA with interoperability features unlocked.

13. Non-Emitting Firm Capacity Resources capable of providing energy capacity in excess of the Customer's current site load that are not otherwise eligible for PGE Schedule 203 may receive a bi-directional meter and be credited at the Customer's retail rate of electricity for energy provided to the grid only when dispatched by PGE as part of this schedule. An interconnection agreement and approval by PGE's Interconnection Team is required prior to installation of such bi-directional meter. The terms and conditions for such credits will be set forth in the agreement.

14. Except as otherwise provided in this schedule, Customers nominating resources and receiving compensation through this schedule may participate in other schedules, but may not receive compensation for the resources nominated in this schedule through another schedule.

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	$22.00	
Three Phase Service	$31.00	
Transmission and Related Services Charge	0.637	¢ per kWh
Distribution Charge		
First 5,000 kWh	6.343	¢ per kWh
Over 5,000 kWh	3.406	¢ per kWh
Energy Charge Options		
Standard Service	7.392	¢ per kWh
or		
Time-of-Use (TOU) Portfolio (enrollment is necessary)		
On-Peak Period	13.055	¢ per kWh
Mid-Peak Period	7.392	¢ per kWh
Off-Peak Period	4.353	¢ per kWh

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

MONTHLY RATE (Continued)

Renewable Portfolio Options
(available upon enrollment in either Energy Charge option)

Renewable Usage	0.940	¢ per kWh in addition to Energy Charge
Renewable Fixed	$1.88	per month per block
	$5.00	per unit in addition to Energy Charge
	$2.50	per month

* Only Customers who are enrolled in a Renewable Portfolio Option (Renewable Usage or Renewable Fixed or Renewable Solar Portfolio Options described herein) may choose the Renewable Habitat Portfolio Option Adder.

RENEWABLE PORTFOLIO OPTIONS

The Customer will be charged for the Renewable Portfolio Option in addition to all other charges under this schedule for the term of enrollment in the Renewable Portfolio Option.

Renewable Fixed Option

The Company will use funds received under this option to cover program costs and purchase 200 kWhs of Renewable Energy Certificates (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.

Renewable Usage Option

Amounts received from Customers under the Renewable Usage Option will be used to cover program costs and acquire RECs and/or renewable energy, all of which will come from new renewable resources.

The Company will also place any funds received from Customers enrolled in this option 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.

SCHEDULE 32 (Continued)

RENEWABLE PORTFOLIO OPTIONS (Continued)

Renewable Solar Option

PGE's Renewable Solar Option will operate through December 31, 2022. Beginning on January 1, 2023, participants currently subscribed to the Renewable Solar Option will automatically transition to two blocks of the Renewable Fixed Option for every unit of the Renewable Solar Option.

The Renewable Solar Option allows participating Customers, on a monthly basis, to support a PGE sponsored utility-scale solar power plant and its renewable attributes. The company will purchase 1 kW of the output and RECs from new solar facilities connected to the Company's electric grid per unit enrolled in the Renewable Solar Option.

In exchange for the Customer's payment of $5.00 per unit per month, the Customer receives the environmental attributes from a local utility-scale solar project and the utility-scale solar project produces 1kW of energy which flows into the grid. Typical purchases may range to the equivalent of a 1, 2, or 3-kW solar panel array. At the end of each year, PGE will provide individual results to the Customer, reporting how much the Customer's energy usage was offset by solar power and the carbon footprint reduction benefit received. The RECs purchased by the Customer will be retired on behalf of the Customer.

Renewable Habitat Adder

The Company will distribute $2.50 per month as received from each Customer enrolled in the Habitat Option to a nonprofit agency chosen by the Company who will use the funds for habitat restoration.

Energy or RECs supporting the Renewable Portfolio Options 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 Renewable Fixed Option and Renewable Usage Option, 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).

SCHEDULE 32 (Continued)

TIME OF USE PORTFOLIO OPTION

On- and Off-Peak Hours*

Summer Months (begins May 1st of each year)

On-Peak	3:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	6:00 a.m. to 3:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

Winter Months (begins November 1st of each year)

On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	10:00 a.m. to 5:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

* 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 AMI meters will observe the regular daylight saving schedule.

** Holidays are New Year's Day (January 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 Saturday, Friday is designated a TOU holiday. If a holiday falls on Sunday, the following Monday is designated a TOU holiday.

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 0.314¢ per kWh for wheeling
- 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.

SCHEDULE 32 (Continued)

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

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.

2. 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.

3. 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.

SCHEDULE 32 (Continued)

SPECIAL CONDITIONS (Continued)

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 on accounts that have been involuntarily disconnected in the last 12 months.

3. The Company will use reasonable efforts to acquire renewable energy, but does not guarantee the availability of renewable energy sources to serve Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer participation.

4. 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.

5. 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.

SCHEDULE 32 (Concluded)

SPECIAL CONDITIONS (Continued)

Pertaining to TOU Option

1. 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. Participation requires a one-year commitment by the Customer. Generally, if a Customer requests removal from the TOU 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.

3. The Customer must take service at 120/240 volts or greater. Single phase 2-wire grounded service is not eligible because of special metering requirements.

4. The Customer must provide the Company access to the meter on a monthly basis.

5. At the end of the Customer's first 12 months of service under the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer’s Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded the Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. No refund will be issued for Customers not meeting the 12-month requirement.

6. The Company will recover lost revenue from the TOU Option through Schedule 105.

7. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date.

8. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge	$35.00	
Transmission and Related Services Charge	0.642	¢ per kWh
Distribution Charge	8.064	¢ per kWh
Energy Charge*		
On-Peak Period	7.933	¢ per kWh
Off-Peak Period	6.433	¢ per kWh

* See Schedule 100 for applicable adjustments.

** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

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.

SCHEDULE 38 (Continued)

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 0.314¢ 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.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0640

SCHEDULE 38 (Concluded)

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	0.687	¢ per kWh
Distribution Charge		
First 50 kWh per kW of Demand***	12.688	¢ per kWh
Over 50 kWh per kW of Demand	10.688	¢ per kWh
Energy Charge	8.238	¢ per kWh

* 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 47 (Concluded)

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will not be for less than one year.

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**	$50.00	
Winter Months**	No Charge	
Transmission and Related Services Charge	0.665	¢ per kWh
Distribution Charge		
First 50 kWh per kW of Demand***	10.847	¢ per kWh
Over 50 kWh per kW of Demand	8.847	¢ per kWh
Energy Charge	8.597	¢ per kWh

* 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 49 (Concluded)

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.

NOVEMBER ELECTION WINDOW

Enrollment for 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 Enrollment Windows 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

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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.

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 3 PM to 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)

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 (all hours)*	On-Peak Charging Price
Direct Current Fast Charger	$5.00 per Session	Flat fee + $0.19 per kWh
Level 2 Charger	$3.00 per Session	Flat fee + $0.19 per kWh
Monthly Membership		
Single Purchase	$25.00 per month	$0.19 per kWh
Multiple Purchase**	$20.00 per month	$0.19 per kWh

* 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 will be made via credit card or other applicable payment method at the PGE charging Station.

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.

2. The pricing listed in this tariff is part of a pilot program and is subject to change.

3. 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 52
NONRESIDENTIAL ELECTRIC VEHICLE CHARGING REBATE PILOT

PURPOSE

This Nonresidential Electric Vehicle (EV) Charging Rebate Pilot provides eligible Customers a rebate towards the purchase and installation of EV charging infrastructure. The overarching goals of the pilot are to:

- Accelerate EV adoption by ensuring adequate charging infrastructure is available to meet customers' charging needs;
- Reduce the cost and complexity of installing EV Supply Equipment that can preclude Customers from deploying charging infrastructure; and
- Create a network of demand-side resources to reduce the costs of serving EV loads by supporting efficient grid operations and future renewables integration.

AVAILABLE

In all territory served by the Company.

APPLICABLE

This pilot is applicable to Nonresidential Customers and property managers/owners of multifamily residence(s) until the cap approved in OPUC Order No. 19-385 and the authorized HB 2165 Monthly Meter Charge budget have been reached. Temporary customers such as construction sites which have not received their certificate of occupancy are excluded.

DEFINITIONS

DCFC EVSE – An EVSE that transfers direct current to the EV.

Electric Vehicle Supply Equipment (EVSE) – The device, including the cable(s), coupler(s), and embedded software, installed for the purpose of transferring electricity between the electrical infrastructure and the EV.

Level 2 (L2) EVSE – An EVSE that transfers alternating current to the EV at 208 or 240 volts.

Operational – An EVSE installed on the premises that is able to transfer energy between the premises wiring and the EV, with all the applicable payment methods (e.g., credit card, phone app, subscription card), and transmit operational data (e.g., energy usage, session start/end times) to the EVSP.

Port – The cable and coupler used to transfer energy from the EVSE to the EV. The number of Ports is defined by the number of EVs that can be charged simultaneously by a given EVSE. There are commonly one or two Ports per EVSE.

SCHEDULE 52 (Continued)

DEFINITIONS (Continued)

Qualified EVSE –The list of qualified EVSE(s) that are available for rebate is determined by the Company and listed on PortlandGeneral.com.

ELIGIBILITY

Eligible Customers must own, lease, or demonstrate control over the site where the EVSE(s) are installed. The Customer will be responsible for procuring the EVSE(s).

ENROLLMENT

The customer enrollment period will be open until funds have been allocated. Eligible Customers may enroll at PortlandGeneral.com.

REBATES

Rebate	Description	Amount
Standard L2 EVSE Rebate	A one-time rebate for the purchase of a Qualified L2 EVSE.	Up to $1,000 per Port; capped at price paid. Customers are eligible for up to $50,000 in Standard L2 EVSE Rebates per site.
Multifamily L2 EVSE Rebate	A one-time rebate for the purchase of a Qualified L2 EVSE installed at a multifamily dwelling.	Up to $2,300 per Port; capped at price paid. Customers are eligible for up to $50,000 in Multifamily L2 EVSE Rebates per site.
L2 Installation Rebate	A one-time rebate for installing a L2 EVSE. Eligible covered costs include the cost of installing electrical infrastructure to support the EVSE, including but not limited to trenching, conduit, switchgear, equipment pads, line extension costs, site restoration, and EVSE installation.	Up to 80% of eligible costs paid or $6,000 per Port, whichever is less. Customers are eligible for up to six L2 Installation Rebates per site.
DCFC EVSE Rebate	A one-time rebate for the purchase and installation of a Qualified DCFC EVSE.	Up to $350 per kW of maximum power output for the EVSE, up to a maximum of $25,000 per Port.

SCHEDULE 52 (Concluded)

REBATES (Continued)

Rebates are available for reservation on a first come-first serve basis per the reservation process identified on PortlandGeneral.com. Eligible Customers must comply with the application instructions and agree to the pilot Terms and Conditions on PortlandGeneral.com to receive the rebate.

Participating Customers will receive the one-time payment by check no later than 90 days from the Company receiving a complete application. All EVSE(s) installed under the pilot are subject to verification by PGE.

Participating Customers must meet the pilot requirements for 10 years. In the event the Participating Customer does not meet this commitment, the Participating Customer commits to reimburse PGE the pro-rata value of the rebate, calculated over the 10-year term.

SPECIAL CONDITIONS

1. Participation in this pilot is not mandatory to install EV charging equipment.

2. The Customer’s charges for Electricity Service under any of the Company’s Standard Service or Direct Access Service schedules are not changed or affected in any way by service under this schedule and are due and payable as specified in those schedules.

3. The Company will defer and seek recovery of all pilot costs not otherwise included in rates.

4. Participating Customers will maintain the EVSE(s) on a Standard Service Schedule. Customers on Direct Access Service must have the participating chargers separately metered and on a Standard Service Schedule.

5. Participating Customers will ensure the EVSE(s) are Qualified and Operational. If a property with EVSE(s) installed under the pilot changes ownership, lesseeship or management, participation in the pilot can be assumed by a new owner, lessee or manager that is willing to meet the pilot requirements.

6. Participating Customers will authorize the EVSP to provide operational data (e.g. energy usage, time of day usage and number of unique drivers) to PGE. Participating Customers agree to allow Company 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 Company-led research such as surveys.

7. Participating Customers may terminate participation in the pilot after providing PGE no less than 30 days’ notice and are subject to the noncompliance reimbursement referenced in this Tariff. At the end of the 10-year term, Participating Customers have the option to continue to participate in the pilot if it is still active, but there is no obligation to do so.

SCHEDULE 53
NONRESIDENTIAL HEAVY-DUTY ELECTRIC VEHICLE CHARGING

PURPOSE

This Nonresidential Heavy-duty Electric Vehicle Charging offering aims to provide learnings about high-powered charging infrastructure, integrated energy storage and on-site generation technologies, and vehicle-to-grid technologies. This schedule is designed solely for the use of electricity as a transportation fuel for heavy duty vehicles. The objectives of this offering are:

- Provide unique opportunities to better understand grid impacts from heavy duty Electric Vehicle charging rates and how complementary grid edge technology (storage, solar, demand response) can help ensure infrastructure can be deployed in ways that benefit the grid
- Offer opportunities to actively engage and provide helpful guidance to customers in the design, deployment, commissioning, and operation of heavy-duty vehicle charging infrastructure
- Obtain heavy-duty Electric Vehicle usage data and gain insights to charging load profiles

AVAILABLE

In all territory served by the Company.

APPLICABLE

This offering is applicable to nonresidential heavy-duty Electric Vehicles manufacturers and operators that deploy high-powered charging infrastructure and also allows for public charging for light, medium and heavy-duty vehicles at the same site, and following conditions:

1. Where the site is made-ready to host or hosts at least one heavy-duty Electric Vehicle charging station capable of an output of at least one MW per port or greater;
2. Where the site is made-ready to host or hosts an energy storage system; and
3. Where the site is made-ready to host or hosts on-site generation.

DEFINITIONS

Charging Infrastructure – All infrastructure and equipment required to deliver energy to an Electric Vehicle, including all civil and electrical infrastructure or equipment located downstream of the Service Meter such as panelboards, switchboards, conductors, pathway, equipment foundations.

Clean Fuels Credits – Non-monetary asset generated by Electric Vehicle Charging Stations under Oregon's Clean Fuels Program

SCHEDULE 53 (Continued)

DEFINITIONS (Continued)

Electric Vehicle Charging Software - Software used to monitor, control, optimize, or perform other functions on Electric Vehicle Charging Stations, or other devices.

Electric Vehicle Charging Station – Equipment designed and installed specifically for the purposes of transferring energy to an Electric Vehicle.

High Power – Electric Vehicle charging rates in excess of 1 MW.

Vehicle Classes - The vehicle weight classes are defined by Federal Highway Administration (FHWA) and are used consistently throughout the industry. Vehicle classes, 1-8, are based on gross vehicle weight rating (GVWR), the maximum weight of the vehicle, as specified by the manufacturer. GVWR includes total vehicle weight plus fluids, passengers, and cargo. FHWA categorizes vehicles as Light Duty (Class 1-2), Medium Duty (Class 3-6), and Heavy Duty (Class 7-8).

Light Duty Vehicle – gross vehicle weight rating less than 10,000 lbs.
Medium Duty Vehicle – gross vehicle weight rating between 10,001 – 26,000 lbs.
Heavy Duty Vehicle – gross vehicle weight rating higher than 26,001 lbs.

ELIGIBILITY

Nonresidential customers that are heavy-duty electric vehicles manufactures and operators may participate in this offering if the following conditions are met:

1. Customer agrees to co-development of a large public charging site for medium- and heavy-duty electric commercial vehicles.
2. The large public charging site is designed to support customer's vehicle charging activities and give access to public to charge heavy-duty vehicles.
3. The site is made ready to host or hosts multiple grid edge technology such as: on-site energy storage, on-site energy generation, demand response capabilities, advanced grid edge controls, and/or other new and novel grid edge technologies.
4. Customer signs up for Oregon Clean Fuels Program
5. Customer will provide electric usage data and operational data to the Company upon request.
6. Customer has not been granted any transportation line extension allowance associated with the subject project.

SCHEDULE 53 (Concluded)

COMPANY RESPONSIBILITY

Upon request from a Customer, the Company will contribute a portion of the project development costs including costs related to investments behind the customer meter. The total aggregate amount of Company contributions under this schedule is $10 million for all projects. Each customer participating in the program is limited to $5 million total. Due to the individualized nature of each project, specifics on the development of the project and payment responsibilities will be contained in a service agreement. Upon termination of the agreement, the Company may remove or abandon Company owned Charging infrastructure in place.

SPECIAL CONDITIONS

1. The Customer's charges for Electricity Service under any of the Company's Standard Service or Direct Access Service schedules are not changed or affected in any way by service under this schedule and are due and payable as specified in those schedules.

2. Prior to receiving service on this schedule, the Customer and the Company must enter into a written agreement, signed by the Customer.

3. Customers receiving service under this schedule will agree to a multi-year term for the agreement. Should the Customer terminate the agreement before the end of the term, the Customer will reimburse the Company for a portion of the capital investment as specified in the service agreement.

TERM

Effective March 15, 2021 through December 31, 2027.

SCHEDULE 54
LARGE NONRESIDENTIAL
RENEWABLE ENERGY CERTIFICATES RIDER

PURPOSE

This rider is an optional supplemental service that supports the development of New Renewable Energy Resources as defined in ORS 757.600. Under this Schedule, a Large Nonresidential Customer may purchase Renewable Energy Certificates (RECs), subject to a minimum purchase and availability of RECs for purchase.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Customers taking service under any of the following PGE schedules: 38, 49, 83, 85, 89, 90, 91, 95, 485, 489, 490, 491, 495, 583, 585, 589, 590, 591, 595, and 689. Customers who are on one of these base schedules who also have schedule 15 area lighting may include those schedule 15 lights in this program.

PRODUCT OFFERINGS

I. PGE Green Resource Mix

This product allows a Customer to purchase RECs, subject to minimum purchase. The product is Green-e® Energy certified, and as a result all RECs purchased on behalf of Green Resource Mix Customers will conform to the Green-e® Renewable Energy Standard for Canada and the United States and are either registered with Western Renewable Energy Generation Information System (WREGIS) or provided via third party audited Green-e attestation.

II. Specified Resource

This product allows a customer to purchase RECs from a specified facility, subject to a minimum purchase. Specified Resource provides the Customer with RECs obtained from specified resources and derived from the following fuels:

SCHEDULE 54 (Continued)

PRODUCT OFFERINGS
Specified Resource (Continued)

1. Wind;
2. Solar;
3. Certified low-impact hydroelectric;
4. Pipeline or irrigation hydroelectric systems;
5. Wave or tidal action;
6. Low emissions biomass (from digester methane from landfills, sewage or waste treatment plants, forest or field residues);
7. Hydrogen derived from photovoltaic electrolysis or non-hydrocarbon derivation process;
8. Geothermal.

Upon customer request, PGE will make best efforts to assist the Customer in identifying a product mix or discrete generators matching the fuel types listed above. Any offering under Specified Resource must be 100% new renewable, which is defined as follows:

(1) a) Placed in operation (generating electricity) on or after January 28, 2000;

b) repowered on or after January 28, 2000 such that 80% of the fair market value of the project derives from new generation equipment installed as part of the repowering, or

c) a separable improvement to or enhancement of an operating existing facility that was first placed in operation prior to January 28, 2000 such that the proposed incremental generation is contractually available for sale and metered separately than existing generation at the facility.

(2) Any project that has been subject to an uprate meant solely to increase generation at a facility – without the construction of a new or repowered, separately metered generating unit – is not eligible for the specified resource offering.

Generation facilities solely owned by PGE (or included in the rate base of PGE) and constructed for the purpose of serving cost-of-service utility customers are not eligible for selection in the specified resource program.

III. DEQ Clean Fuels Compliant Resource

This product allows Customers to purchase qualifying RECs that meet the requirements to generate incremental clean fuels credits as part of the Oregon Clean Fuels Program administered by the Oregon Department of Environmental Quality (DEQ) under ORS 468A. Under this option, PGE only offers RECs that meet the Clean Fuels Program requirements.

SCHEDULE 54 (Continued)

RATE

1. With regard to Offering 1, PGE Green Resource Mix:

   a. The rate for this product is specified in the Green-e ® Energy required disclosure documents, a copy of which is provided to the Customer.

   b. The rate for Offering 1 shall be comprised of three components: the market price for the REC, selling, general, and administrative (SG&A) costs, and a risk premium fee.

   c. The market price for RECs may change but will be based on expected market conditions and program demand. The SG&A costs will be calculated to ensure that program participants bear the entirety of these costs, and these costs will be uniformly charged to customers. The risk premium accounts for PGE shareholder risk from entering a fixed price contract to supply RECs and will not exceed PGE's currently approved rate of return. The risk premium will be the same for all customers participating in this offering.

   d. A minimum REC purchase of 1,000 kWh per month, or annual equivalent, is required.

2. If a Customer chooses to participate in the Specified Resource or DEQ Clean Fuels Compliant Resource program, the same rate components as described in Offering 1 shall apply, but the price may differ and is subject to execution of a written contract.

SPECIAL CONDITIONS

1. The Customer may enroll to purchase any option outlined in this tariff after entering an agreement with the Company. Participation will commence within 60 days of the Company providing Customer with confirmation of a properly executed agreement that includes Customer's signature, which can be digital.

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this offering, poor credit history is defined as: a) having received two or more final disconnect notices in the past 12 months; or b) having been involuntarily disconnected in the past 12 months.

3. The Company makes no representations as to the impact on the development of renewable resources from Customer participation.

SCHEDULE 54 (Concluded)

SPECIAL CONDITIONS (Continued)

4. The Company is not required to own renewables or to acquire energy from renewable resources simultaneously with Customer usage.

5. PGE will purchase RECs sufficient to meet all Customer commitments, and retire them annually.

6. The Company will charge or credit all incremental costs and revenues associated with the provision of services under this schedule to nonutility accounts.

7. PGE offers this product through a competitive operation and is provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 860-038-0640.

8. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other REC providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to allowing the Company's Large Nonresidential REC program to use the bill inserts.

9. PGE will limit the number of RECs that PGE offers for purchase under the PGE Green Resource Mix option, as well as the number of Green Resource Mix RECs bought by any individual customer based on RECs PGE has purchased. PGE reserves the right to change the limit based on the current program price and market price of RECs. The availability of Specified Resource and Clean Fuels Compliant RECs is also dependent on market supply and pricing and may be limited. In the event that RECs are limited in supply, there will be a waitlist for any new participants that will be served on a first come first served basis.

SCHEDULE 55
LARGE NONRESIDENTIAL
GREEN ENERGY AFFINITY RIDER (GEAR)

PURPOSE

This tariff is an optional supplemental service that supports the development of local new renewable resources as defined in Oregon Revised Statute (ORS) 469A.025. Under this Schedule, a Nonresidential Customer may purchase a subscription share of a new renewable facility matched to the preference of the Subscribing Customer (with a maximum subscription of the Customer's yearly consumption).

DEFINITIONS

Local - means that the facility that generates the qualifying electricity for which the bundled renewable energy certificate is issued is located in the United States and within the geographic boundary of the Western Electricity Coordinating Council (WECC). This definition is consistent with ORS 469A.135. Portland General Electric Company (PGE) may seek specific resource locations at the Subscribing Customer's request.

Bundled Renewable Energy or Bundled Renewable Energy Certificates - means a renewable energy certificate (REC) for qualifying electricity that is acquired by an electric utility or electricity service supplier by a trade, purchase, or other transfer of electricity, or by an electric utility by generation of the electricity for which the REC was issued. This definition is consistent with ORS 469A.005.

Energy Value - means the energy value calculated using the AURORA model and the same methodologies and assumptions described in the Integrated Resource Plan (IRP) or IRP update, at the time the resource contract is executed.

Capacity Value - means the value of capacity, calculated as described in PGE's IRP, at the time the resource contract is executed.

Company-Owned Resource - means a resource developed or purchased by the Company. Should the Company propose to own a resource serving this program, that proposed ownership is subject to meeting the requirements of Public Utility Commission of Oregon (OPUC) Order 21-091 regarding company ownership, and OPUC Order 21-263.

Customer Supply Option (CSO) - means a resource identified and selected by the Customer, with assistance from PGE in identifying a resource if requested by the Customer, and contracted as a Power Purchase Agreement (PPA), or Company-Owned Resource, or other means consistent with the Minimum Requirements. CSO eligible Customers, are Customers with greater than 10 aMW in load or as otherwise approved by the Public Utility Commission of Oregon (OPUC).

SCHEDULE 55 (Continued)

DEFINITIONS (Continued)

Minimum Requirements - means the minimum requirements for available commercial structures. The minimum requirements may be found at https://portlandgeneral.com The minimum requirements may be updated from time to time to reflect PGE's criteria from its latest Commission accepted renewable request for proposals.

PGE Supply Option (PSO) - means the renewable resource(s) for Subscribing Customer(s) is identified and procured by PGE to meet aggregate Subscribing Customers loads in the program. The PSO resource could be contracted as a PPA, a Company Owned Resource, or other means consistent with the Minimum Requirements.

Power Purchase Agreement (PPA) - means a long-term electricity supply agreement between a power producer and PGE. The PPA is one means of procuring renewable energy for Subscribing Customers in this voluntary supplemental service program.

Subscribing Customer - means a PGE Nonresidential Customer served by retail base service, who elects to receive voluntary supplemental service through this program.

AVAILABLE

In all territory served by the Company.

APPLICABLE

This schedule is available – subject to capacity approved by the Oregon Public Utility Commission (OPUC) from time to time – to all Nonresidential Customers each of whose aggregate demand across all retail schedules exceeds 30kW. In the event that a Subscribing Customer has multiple accounts – some of which may fall under 30kW of demand – the Subscribing Customer will be allowed to aggregate all Nonresidential accounts.

GENERAL PROVISIONS

1. Customers enrolling in this schedule commit to a subscription share of a new renewable facility, matched to the preference of the Subscribing Customer (with a maximum subscription of the Customer's yearly consumption).

SCHEDULE 55 (Continued)

GENERAL PROVISIONS (Continued)

2. The Company will ensure that renewable energy resources utilized under this schedule are new, meaning they are or have been operational no earlier than one year prior to the resource being included in the program, and may include energy storage associated with Renewable Portfolio Standard (RPS)-eligible resources as defined in ORS469A.120(2)(a). A Subscribing Customer using the CSO shall ensure that renewable energy resources utilized under this schedule are or have been operational no earlier than one year prior to the resource being included in the program, and may include energy storage associated with RPS-eligible resources as defined in ORS469A.120(2)(a).

3. The Company shall procure Bundled Renewable Energy on the Subscribing Customer's behalf – or through collaborative sourcing with a customer for the CSO – from a new renewable energy facility. In the event of yearly under-generation from the renewable energy resource, the Company will purchase RECs on the Subscribing Customer's behalf to ensure that the Customer's subscribed amount is covered under this tariff. In the event that the renewable energy supplier is no longer able to supply bundled renewable energy to the Subscribing Customer, the Company, at the election of the Subscribing Customer, shall make reasonable efforts to procure a new resource on behalf of the Subscribing Customer as soon as practicable with the cost of the renewable energy to the Subscribing Customer revised accordingly.

4. This schedule is for supplemental retail service, and will be served solely as a supplement to retail base rates by the Company. Subscribing Customers who leave PGE's retail supply service, or who are not on PGE's retail supply service, are ineligible for this program.

5. The Company will retire the RECs associated with the energy procured on behalf of the Subscribing Customer, or the Subscribing Customer may retire the RECs itself.

6. Should the Company propose to own a resource serving this program, the Company will follow Commission direction including proposing accounting safeguards for separate accounting for the Company owned GEAR resource. The renewable energy GEAR resource may be included in rate base so long as the asset(s) can be accounted for separately from the Company's general rate base. The proposed safeguards will prevent the commingling of renewable resources serving this program with other assets that are in rate base for the purpose of serving non-GEAR customers[1].

1.This requirement is found in Commission Order 21-091 at page 12.

SCHEDULE 55 (Continued)

ENROLLMENT PROCESS

When the Company opens the queues for Customer enrollment, Customers can elect to enter either the CSO or PSO queue. The Company will maintain separate and distinct queues for the CSO and PSO options. Customers will be allowed to enter one queue and will not be allowed to be simultaneously enrolled in both the CSO and PSO queues. Customer placement in the program option queue they elect will be based on the timestamp that the Company receives electronically when the Customer returns the signed, non-binding letter of interest. Customers will submit their letter of interest and the amount of load. Enrollment will remain open and PGE will maintain each respective queue order until all available capacity is fully subscribed by Customer contracts. Subject to the program eligibility requirements, a Customer may withdraw their election in writing and return a signed non-binding letter of interest to be placed in the other queue, and their new queue position will be based on the timestamp that the Company receives electronically when the Customer returns the new signed non-binding letter of interest received by the Company.

1. The Customer shall independently make the selection of the CSO resource for enrollment in the program.

2. The Customer will determine when to engage PGE in the CSO resource identification and solicitation process. Should the Customer approach PGE for help during the identification and/or solicitation process for a CSO resource, PGE will assist the Customer. The Company will provide written notice of the Customer’s request to the Staff of the OPUC.

3. If a CSO Customer elects to seek PGE’s help for resource identification or solicitation, the Company will ensure the costs of such efforts are separately tracked and collected via the Customer’s program administration fee to avoid cost shifting.

4. Given that the resource will be interconnected and delivering energy into PGE’s system, the Company will be the entity contracting for the resource to serve the CSO Customer and must be provided the opportunity, in the course of the development of an agreement between a CSO Customer and a third-party to review and address contract terms that would shift costs or risks to other Customers or PGE shareholders. The Subscribing Customer may determine the appropriate point in time to involve PGE during contract negotiations, but must allow PGE sufficient time to review and address contract terms.

5. The Company will not help with CSO resource identification or design a CSO resource solicitation if the Company plans to submit a Company provided resource into such solicitation. Any submission of a utility developed resource to a CSO Customer would be in the form of a formal response to a Customer’s solicitation.

6. The same renewable energy project may support both the CSO and PSO; however, contracts for the CSO and PSO will be separately negotiated.

SCHEDULE 55 (Continued)

ENROLLMENT PROCESS (Continued)

7. The Company will accept the commercial structure of the resource that is selected by the CSO Customer, subject to the allowable commercial structures and applicable requirements as identified in the posted Minimum Requirements.

8. Should PGE propose a Company Owned Resource for this program, PGE will submit to all applicable Commission processes, including the Commission's competitive bidding rules unless such rules are waived, and initiate a Commission process to determine appropriate segregation of the asset. If no processes under the competitive bidding rules are required for the acquisition of a project by the Company for the GEAR program, the Company nevertheless commits to provide for a process that would allow Commission review into the acquisition before it is completed.

9. PGE will not establish capacity limits with regard to Customers enrolling in the CSO option.

10. If PGE anticipates customer demand for the PSO offering exceeds 100% of the offered capacity, PGE will limit each participants allowable capacity. The limit will restrict subscription so that no customer can subscribe to more than 20% of the total offered capacity for the upcoming offering. In the event remaining capacity is available, PGE will allocate this remaining available capacity to customers requesting an amount in excess of the limit in the order of the Customer's queue position. In advance of the enrollment queue opening to Customers, PGE will publish the 20% limit on capacity and the date when it will allocate any available remaining capacity on the Company's website.

PRICING STRUCTURE

1. While enrolled in this Rider, the Subscribing Customer shall continue to take service under – and pay the components of – their applicable base rate schedule and all supplemental schedules and riders.

2. The Rider rate will pass to Subscribing Customers the costs of acquiring the renewable energy resource and operating this supplemental program. The Subscribing Customer will be credited with the Energy Value and Capacity Value (as applicable). These charges and credits will be determined and billed as follows:

   - The cost for each MWh of the applicable resource generated and delivered to the Subscribing Customer;
   - An administrative charge to account for program costs, integration, shaping, firming, and other relevant program expenses;
   - A risk adjustment, if applicable;
   - Credit for Energy Value and Capacity Value, as defined in the "Definitions" section above.

SCHEDULE 55 (Concluded)

PRICING STRUCTURE (Continued)

3. Non-subscribing Customers will not be subject to resource costs, administrative costs, or any cost associated with this program, except for the crediting of Energy Value and Capacity Value, as applicable.

CREDITS

1. The bill credit amount, the sum of the Capacity and Energy Values, represents the amount that cost of service Customers are paying to the Subscribing Customer(s), for the resource.

2. The bill credit amount is determined by the Company, using the Company's IRP methodology to determine the Capacity and Energy Values. The credit values for energy and/or capacity will be determined at the time of resource procurement, fixed over the contract period.

3. The Company shall submit for regulatory review the rate and credit calculations agreed upon by the Company and the Subscribing Customer through a filing to the Staff of the OPUC.

4. For the CSO option, Customers may apply to the PUC for a floating credit on a case by case basis. A floating credit is one that updates in a predictable way periodically and while it does not guarantee net savings to a participant, it may result in participant net savings[1].

CONTRACT PERIOD

The Subscribing Customer may elect to subscribe to this Rider for a term between 5 and 20 years, as agreed upon between the Company and the Subscribing Customer. The Subscribing Customer shall enter into a contract for service under this Rider for a term and with terms and conditions consistent with the terms and conditions of the contract with the renewable energy supplier or the life of the resource, or as agreed upon between Company and Subscribing Customer (and subject to regulatory review). If the Subscribing Customer requests an amendment to or termination of the subscription agreement, or defaults on the subscription agreement before the expiration of the term of the agreement, the Subscribing Customer shall be subject to termination and default provisions as contained within the subscription agreement between the Subscribing Customer and the Company.

1.For Commission discussion of the floating credit approach, see Order 19-075 at pages 5-6.

SCHEDULE 56
FLEET ELECTRIFICATION MAKE-READY PILOT

PURPOSE

This Fleet Electrification Make-Ready Pilot provides eligible customers with incentives to install Electric Vehicle (EV) charging infrastructure to support fleet vehicles. The overarching goals of the pilot are to:

- Enable and accelerate 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;
- Create a network of demand-side resources to reduce the costs of serving EV loads by supporting efficient grid operations and future renewables integration;
- Better understand the customer and barriers and opportunities in the fleet electrification market;
- Identify areas for utility process improvement with respect to fleet electrification; and
- Generate an empirical data set that can be leveraged to inform existing utility analyses, support customers in transitioning to electric fleets, and develop future products and programs.

AVAILABLE

In all territory served by PGE.

APPLICABLE

This pilot is applicable to nonresidential customers that use or operate fleets within PGE's service area.

DEFINITIONS

Activation Date – date that PGE first determines an EVSE is Operational.

Electric Vehicle Supply Equipment (EVSE) – the device, including the cable(s), coupler(s), and embedded software, installed for the purpose of transferring electricity between the electrical infrastructure at the Site and the EV.

Electric Vehicle Service Provider (EVSP) – provider of connectivity across a network of EVSE(s).

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.

SCHEDULE 56 (Continued)

DEFINITIONS (Continued)

Make-Ready Cost – the cost of Make-Ready Infrastructure and Line Extension, excluding those accounted for in the Line Extension Cost.

Make-Ready Infrastructure – the infrastructure at the Site to deliver electricity from the Service Point to the EVSE(s), including any panels, stepdown transformers, conduit, wires, connectors, meters, and any other necessary hardware.

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.

Qualified EVSE – list of qualified EVSE(s), determined by PGE.

Qualified EVSP – list of qualified EVSP(s), determined by PGE.

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 Owner – entity holding title to the Site.

ELIGIBILITY

Eligible 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 Customers must own or lease the Site.

ENROLLMENT

The customer enrollment period will be open for three years, 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)

INCENTIVE

Pilot participants 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 15; or
- The participant's Make-Ready Costs; or
- $750,000.

SPECIAL CONDITIONS

1. Participation in this pilot is not mandatory to install EV charging equipment.

2. 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.

3. PGE will locate, design, install, own, operate and maintain the Make-Ready Infrastructure. EVSE(s) will be separately metered from any other load at the Site.

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 participating customer's custom incentive is in excess of $250,000, the participating customer agrees that PGE may verify the participating customer's creditworthiness at any time and seek financial security to ensure the Participating customer is able to meet its obligations as set forth in the participation agreement.

7. The participating 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.

8. The participating customer must maintain the EVSE(s) on a Qualified Service Schedule for 10 years following the Activation Date of the first Qualified EVSE installed at the Site.

9. The participating customer will ensure the EVSE(s) remain Qualified EVSE(s) and Operational for 10 years following the Activation Date of the first Qualified EVSE installed at the Site.

SCHEDULE 56 (Concluded)

SPECIAL CONDITIONS (Continued)

10. The participating 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 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.

11. The participating customer will authorize and require the Qualified EVSP to provide operational data (e.g. charging session data, energy interval data) to PGE. The participating customer agrees 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.

12. If the Site changes ownership or lesseeship, participation in the pilot may be assumed by the new owner or lessee if it is willing to meet the pilot requirements. The participating 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.

13. 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.

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	$4,950.00	$4,900.00	$6,400.00
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$2.45	$2.42	$2.38
Distribution Charges			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.61	$1.59	$1.59
Over 4,000 kW	$1.30	$1.28	$1.28
per kW of monthly On-Peak Demand	$1.56	$1.54	$0.12
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	0.205 ¢	0.203 ¢	0.201 ¢
Energy Charge			
per kWh	See Energy Charge Below		

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned by the Customer. Initially, the Customer's Baseline Demand will be the Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations. Subsequently, Customer may select its Baseline Demand in accordance with the applicable notice requirements set forth in this schedule adjusted for changes in load and planned generator operations. Planned generator operations include the Electricity planned to be produced by the generator as well as the Customer's plans to sell Electricity produced by the generator to the Company or third parties. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 76R, monthly Demand charges under Schedule 75 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

For the first three months of service under this schedule, the Facility Capacity will be equal to the Customer's Baseline Demand. Starting with the fourth month, the Facility Capacity will be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Period, but will not be less than the Customer's Baseline Demand.

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated, instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to the Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves, transition a Customer's load to Unscheduled Power. A Customer on Schedule 75 must take Spinning Reserves in all Billing Periods that its generator is expected to operate. Spinning Reserves are not required for a Customer with Reserved Capacity of 2,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's Load Reduction Plan must be approved by the Company.

Self-Supplied Reserves

Customers with nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to the Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

Supplemental Reserves Load Reduction Plan

In lieu of self supplying Supplemental Reserves through a self-supply agreement, a Customer may provide Supplemental Reserves through the submittal to the Company of a Load Reduction Plan that demonstrates the ability to reduce load within the first ten minutes of generator failure and specifies a kW amount of load reduction equal to 3.5% of the Reserved Capacity.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES (Continued)

Supplemental Reserves Load Reduction Plan (Continued)

The Load Reduction Plan also will specify the notification processes for delivery of Supplemental Reserves, the requirements for Customer delivery of requested Supplemental Reserves, the requirements for Customer notification to Company of any changes in the ability to supply Supplemental Reserves, the settlement process to be used when Supplemental Reserves are supplied by the Customer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. The Customer Load Reduction Plan must be approved by the Company. If approved by the Company, and adhered to by the Customer, a credit to the Supplemental Reserves charges will be applied to Customer's bill based on the Supplemental Reserves Level as specified in the Load Reduction Plan.

If Customer fails to follow the Company-approved Load Reduction Plan, all Supplemental Reserves credits for the subsequent three months (Penalty Period) will be forfeited. If the Customer satisfactorily follows the Company-approved Load Reduction Plan during the Penalty Period, the Load Reduction Plan kW credit will be reinstated at the end of the three month Penalty Period.

If the Customer fails to follow the Company-approved Load Reduction Plan a second time during the Penalty Period and the following three months, the Load Reduction Plan will be terminated.

The duration of the Penalty Period will not be limited by the establishment of a new service agreement under this schedule.

Following termination or contract expiration, Customer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Customer is able to demonstrate the load reduction capability of the Plan to Company's satisfaction.

Notwithstanding the above, Customer may terminate the Company-approved Load Reduction Plan upon giving 6 month written notice to Company.

ENERGY CHARGE

The Energy Charge is comprised of the following:

Baseline Energy

Unless otherwise agreed to, the Baseline Energy is the Energy normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned. Usage on an hourly basis up to and including the Baseline Demand will be considered Baseline Energy. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Energy when the Customer is new to the Company's system or has changed operations from the previous year.

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 0.314¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, 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 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.

On-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.

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 75 (Continued)

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy and Scheduled Maintenance Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written service agreement specifying the terms and conditions of service, the Customer's Baseline Demand and Energy Pricing Option under Schedule 89, the Customer's Reserved Capacity, the Company's and Customer's contact information, and any other information necessary for implementation of service under this schedule. The term of the service agreement will be one calendar year (except that the term of the first service agreement will be the remainder of the year when signed plus the next calendar year) and will renew annually thereafter for successive one year terms, unless the Customer gives 90 days prior written notice. These terms and conditions will be consistent with this schedule.

2. A Customer must inform the Company within 30 minutes of taking Unscheduled Energy at a rate of five MW or greater and inform the Company of the anticipated time that the generator will return to normal operations.

3. Customers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Service Point and total Generator output.

4. If the Customer is served at Primary or Subtransmission Voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment and wiring will be of types and characteristics approved by the Company and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Period the Customer is billed for Transmission and Related Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8), Regulation and Frequency Response Service will be credited to the Transmission and Related Services Charge under this schedule. The credit will be the actual OATT demand incurred but will not exceed the Monthly Demand for the Schedule 75 monthly Transmission Demand multiplied by the applicable OATT (OATT Schedules 7 or 8) and such credit will not exceed the Transmission and Related Services Charge incurred under this schedule.

SCHEDULE 75 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Customer will not use Electricity sold by the Company to directly or indirectly make or continue a delivery of Electricity to another Customer or wholesale power purchaser.

7. A Customer's failure to inform the Company of the use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

8. The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the Customer's generating capacity.

9. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Company or Customer provides the following notice:
   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Company or Customer may make one such request per calendar year and will provide at least 6 months written notice;

   b) for a change in Baseline Demand that is greater than 5 MW, the Company or Customer must provide at least 13 months written notice with such change effective on January 1 of the applicable year. Any subsequent notice by the Company or Customer under this special condition must be made consistent with these notice requirements.

10. If the Customer's Baseline Demand is increased, any Energy used above the initial Baseline Demand, and below the revised Baseline Demand will be priced at the Daily Price Option contained in Schedule 89 unless the Customer has given the required notice to change the applicable Schedule 89 Energy Charge Option.

11. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council guidelines.

12. If the Customer is receiving service under this schedule and Schedule 76R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 76R Special Conditions.

13. A Customer may not change service options until it has satisfied any Baseline Energy term provisions as established in Schedule 89.

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) On-Peak Demand per day	$0.095	$0.094	$0.093
Daily ERP Demand Charge			
per kW of Daily ERP Demand during On-Peak hours per day**	$0.061	$0.060	$0.005
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 hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 76R (Continued)

ENERGY NEEDS FORECAST (ENF) AND ECONOMIC REPLACEMENT POWER (ERP)

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF). The ENF specifies the amount of Electricity in mWh for each hour that ERP is requested to serve some or all of the Customer's load normally supplied by the Customer's generation (amounts in excess of the Baseline Energy under Schedule 75) pursuant to the requirements of the applicable ERP Supply Option.

Each ENF will be based on the Customer's expected Energy requirements and the Customer will use best efforts to conform Actual Energy usage to the ENF and utilize Energy imbalances to the minimum extent reasonably possible.

The ENF will specify the expected ERP needed by hour. The Customer will deliver the ENF to the Company in accordance with Company procedures. The Company will inform the Customer as to the availability of ERP at the time of the ENF request. The Company can choose to provide all or a portion of the ENF and will inform the Customer of any such adjustment to the submitted ENF. Customer acceptance of such modification of the ENF by the Company will be confirmed within 15 minutes of the proposed ENF revision by the Company. If the Company does not inform the Customer that it is modifying the submitted ENF within 30 minutes of receipt of the ENF, the ENF will be deemed accepted by the Company.

The Customer may utilize only one of the ERP supply options on any day.

ERP Supply Options

Each request for ERP will originate from the requesting Customer and requires an ENF from the customer. At the time of an ENF submittal, Customer must designate which of the available ERP pricing options the ENF applies to for purposes of pricing and price quotes. Customer is solely responsible for the accuracy of an ENF and the acceptance or rejection of a price quote.

ENF Options for ERP

Short Notice ENF: The Customer must provide the ENF to the Company a minimum of 90 minutes prior to the first hour that Short-Notice ERP is requested.

Daily ENF: At the Customer's option, between 0600 and 0615 of a Pre-Schedule Day, the customer will communicate with PGE in an agreed-to manner the customer's interest in purchasing ERP power for delivery the next day or days (as required by the daily day-ahead pre-scheduling protocols of Western Electricity Coordinating Council ("WECC")). Customer will at this time provide the Company with the ENF for HLH or LLH or both for the day or days of delivery. The ENF may differentiate between HLH and LLH hours but will be a flat (constant) MW amount for the each HLH or LLH or both.

Monthly ENF: Not less than 7 business days prior to the last trading day for the upcoming quote month, the customer may submit an ENF for the next month. The ENF may be differentiated into HLH or LLH for the entire month.

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 0.314¢ 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.

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 0.314¢ 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.

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 0.314¢ 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.

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.

On-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. Off-peak hours (Light Load Hours, LLH) are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all hours Sunday.

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 0.314¢ per kWh for wheeling, plus losses.
- 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 0.314¢ per kWh for wheeling, plus losses.

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 0.314¢ per kWh for wheeling, plus losses.

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 0.314¢ per kWh for wheeling, 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 76R (Concluded)

SPECIAL CONDITIONS (Continued)

3. All charges and requirements of Schedule 75 will apply except as provided for under this schedule.

4. ERP supplied will not be resold.

5. The Company may interrupt ERP due to transmission constraints.

6. The Customer must notify the Company's Merchant Power Operations, at a specified phone number, as soon as practical of otherwise unplanned load deviations greater than 5 MW that are expected to last one hour or longer.

7. If Customer is unable to use or accept delivery of ERP due to circumstances beyond its control, the difference between Actual Energy and the ENF will be treated as Imbalance Energy.

8. Upon mutual agreement between the Company and Customer, the otherwise applicable Schedule 75 monthly Basic and Facility Capacity Charges will be replaced by a flat monthly Basic and Facility Capacity Charge billed under this schedule. The flat monthly Basic and Facility Capacity Charge will be set to maximize the economic value of sales under this schedule.

9. The Company is not responsible for providing market information to Customer.

10. The Company has no obligation to provide the Customer with ERP except as explicitly agreed to by both parties.

11. Each day of flow will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

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 0.314¢ 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.

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 81 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will terminate five business days from initial purchase.

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	$40.00
Three Phase Service	$50.00
Transmission and Related Services Charge	
per kW of monthly On-Peak Demand	$2.45
Distribution Charges**	
The sum of the following:	
per kW of Facility Capacity	
First 30 kW	$5.70
Over 30 kW	$5.60
per kW of monthly On-Peak Demand	$1.56
Energy Charge	
On-Peak Period per kWh***	5.253 ¢
Off-Peak Period per kWh***	3.753 ¢
Generation Demand Charge	
per kW of monthly On-Peak Demand	$8.48
See below for Daily Pricing Option description.	
System Usage Charge	
per kWh	1.051 ¢

* 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 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 0.314¢ 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.

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 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

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 83 (Continued)

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

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, 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 83 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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	$1,040.00	$920.00
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$2.45	$2.42
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$3.18	$3.15
Over 200 kW	$3.08	$3.05
per kW of monthly On-Peak Demand	$1.56	$1.54
Energy Charge		
On-Peak Period per kWh***	5.118 ¢	5.068 ¢
Off-Peak Period per kWh***	3.618 ¢	3.568 ¢
Generation Demand Charge		
per kW of monthly On-Peak Demand	$9.56	$9.45
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.248 ¢	0.245 ¢

* 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 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 0.314¢ 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.

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 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

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 85 (Continued)

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

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum monthly on-peak Demand (in kW) will be 100 kW for primary voltage service.

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 85 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 86
DEMAND BUY BACK RIDER
NONRESIDENTIAL

PURPOSE

This rider is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce their Electricity usage in return for a payment, at times and prices determined by the Company.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Industrial, Commercial and General Service electric Customers served under Schedules 38, 83, 85, 89, 90 and 99 who satisfy the conditions contained in this rider. Customers must execute a Demand Buy Back Agreement prior to receiving service and have the capability to reduce not less than 250 kW aggregated from one or more points of delivery for each hour during a Buy Back Event.

BUY BACK CREDIT DETERMINATION

Energy Price

The Energy Price will be a price or prices quoted by the Company for a specified Buy Back Event, subject to requirements and other conditions described in Special Conditions.

Hourly Credit

Buy Back Amount (kWh) **X** Energy Price **=** Hourly Credit

The Hourly Credit is the amount owed to the Customer for each hour of the Buy Back Event. The Hourly Credit is determined by multiplying the Buy Back Amount by the Energy Price. The Hourly Credit will not be less than zero.

Buy Back Credit

The Buy Back Credit is the amount paid to the Customer for its Electricity reduction during a Buy Back Event and is the sum of each Hourly Credit during such event (minus any amounts owed as a result of failure to comply during an Extended Buy Back Event).

PAYMENTS

The Company will pay the Buy Back Credit to the Customer within 60 days of the Buy Back Event.

SCHEDULE 86 (Continued)

BUY BACK AMOUNT

The Buy Back Amount will be the difference between the Customer's Baseline Usage and the Customer’s measured hourly load during the term of the Buy Back Event. The Customer will participate by operating below its Baseline Usage for the length of the requested Buy Back Event. A participating Customer’s measured load for purposes of determining a Buy Back Amount must be zero kW or greater. The Company at its discretion may limit the Buy Back Amount to the Buy Back Pledge.

BASELINE USAGE

The Customer’s Baseline Usage is dynamic and is defined as the average Energy usage for each hour for a minimum of approximately 14 typical operational days prior to the Buy Back Event. Typical operational days exclude days that a Customer has participated in a Buy Back Event. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Usage when the Customer's Energy usage is highly variable.

BUY BACK PLEDGE

The Buy Back Pledge is the amount of Energy the Customer commits to curtail when it agrees to participate in a Buy Back Event. The Buy Back Pledge must be at least 250 kW and can vary by hour. The Customer must submit to the Company the amount of the Buy Back Pledge prior to the Buy Back Event through the specified notification method. The Customer will receive an acceptance confirmation for its pledge prior to the start of the Event. A Buy Back Pledge cannot exceed Baseline Usage and is the expected Buy Back Amount for the Buy Back Event.

NOTIFICATIONS

The Company will utilize a secure Internet web site as the primary method to notify participants of Buy Back Events and to receive Customer notification of participation in a Buy Back Event. The Company’s notification will include a time and date by which the participating Customers must submit a Buy Back Pledge. The Company will provide the Customer with access codes to the secure Internet web site. Other methods of notification such as facsimile, telephone and electronic mail, may be utilized at the discretion of the Company.

BUY BACK EVENT

A Buy Back Event specifies the dates, times and duration of a Company requested load reduction and will be for one or more consecutive hours. A Buy Back Event with a duration of more than 24 consecutive hours is an Extended Buy Back Event. An Extended Buy Back Event may include requirements for a single, continuous Buy Back Pledge to which the participant must comply for the duration of the event. More than one Buy Back Event may occur in one day and more than one Buy Back Event may be in effect simultaneously.

SCHEDULE 86 (Continued)

BUYBACK EVENT (Continued)

The Company is not obligated to call a Buy Back Event, and the Customer is not obligated to reduce Energy upon being advised of a Buy Back Event. The Company will not be liable for failure to advise a Customer of a Buy Back Event.

FAILURE TO COMPLY WITH BUY BACK PLEDGE

Single Day Buy Back Event

If a Customer's Buy Back Amount for any hour is less than 90% of the Customer's Buy Back Pledge, the Company may refuse to accept future pledges from the Customer until the capability to meet their pledge is demonstrated in a manner acceptable to the Company.

Extended Buy Back Event

If a Customer's actual Buy Back Amount for any hour of an Extended Buy Back Event (as defined in Special Condition 3 below) is less than the Buy Back Pledge, the Customer will pay to the Company an amount equal to the applicable Intercontinental Exchange Mid-Columbia Daily Electricity Firm On-Peak Price Index, plus 5%, multiplied by the difference between the Buy Back Pledge and the actual hourly Buy Back Amount for all of the hours during the Extended Buy Back Event that the pledge is not met. The Company may for any Extended Buy Back Event establish other lesser consequences for noncompliance.

SPECIAL CONDITIONS

1. The Customer and Company must execute a Demand Buy Back Agreement prior to receiving service on this rider.

2. The Customer may not participate in this rider until the Company has installed metering that records usage in 15 minute intervals. The Customer will provide communication service to the meter if requested by the Company. Service under this rider is subject to meter availability.

3. The Company is not responsible for any load reduction that has not been confirmed and accepted by the Company.

4. The Company is not responsible for any consequences to the participating Customer that result from a Buy Back Event or the Customer’s effort to reduce Energy in response to a Buy Back Event.

5. This schedule is not applicable when the Company requests or initiates load interruptions affecting a Customers meter for a system emergency.

SCHEDULE 86 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Company may utilize a third party to provide program management support for this rider. The Company has the right to provide the Customer's Energy consumption data to a third party for the purpose of providing service under this rider. Such information will be provided to a third party subject to confidentiality requirements.

7. The Company may quote a separate Energy Price for Customers that shift load in conjunction with a Buy Back Event. Load shifting is the change in a Customer's Energy usage during non-Buy Back Event hours to compensate for reduced Energy usage during the Buy Back Event. For purposes of this rider, load shifting occurs when the Customer's Energy usage during the 24 hours preceding or following a Buy Back Event (or any day of an extended Buy Back Event) increases from the applicable hourly Baseline Usage by more than 50% of the Buy Back Amount.

8. The Company and the Customer will test the Customer's ability to reduce Energy usage prior to the Customer's participation in a Buy Back Event.

9. If a Customer takes service under a direct access schedule (when available), it is no longer eligible to participate in this rider.

10. Should an error occur in the calculation of the Buy Back Credit or any of the underlying components, the Company will provide written notice to the Customer detailing the circumstances and amount of adjustment. The Customer will return the overpayment to the Company or the Company will pay the underpayment to the Customer, as applicable, within a period of time agreed to by the Customer and the Company after notice has been given.

11. The Company will not cancel or shorten the duration of a Buy Back Event once notification has been given.

TERM

Service under this schedule will not be for less than a one-year term.

SCHEDULE 88
LOAD REDUCTION PROGRAM

PURPOSE

The Load Reduction Program is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce Electricity usage to a Company-determined level during an Emergency Curtailment as described in Rule C(2)(B) in exchange for partial exemption from Emergency Curtailments.

AVAILABLE

In all territory served by the Company but total pledges will not exceed 5% of Company primary voltage circuits.

APPLICABLE

To an individual or a group of Large Nonresidential Customers receiving Electricity Service under Schedules 83, 85, 89, 90, 485, 489, 490, 583, 585, 589, 590 and/or 689 from one or more Service Point(s) (SPs) but from the same dedicated primary circuit and able to reduce Baseline Usage from the primary circuit by a minimum of 15%. Customers applying as a group must be represented by a Lead Customer. A group may consist of multiple SPs under one Customer name that are all located on the same primary circuit. Participation is dependent upon satisfaction of all conditions contained in this schedule.

BASELINE USAGE

The Baseline Usage is defined as the average usage for each hour for a minimum of 14 typical operational days prior to the Emergency Curtailment. Typical operational days exclude days that a Customer has participated in either an Emergency Curtailment or a Demand Buy Back Event (Schedule 86). Holidays and weekends will be excluded when determining the Baseline Usage except when the Emergency Curtailment includes weekends or holidays. The Customer may request that specific days be excluded from the 14-day baseline calculation upon demonstrating to the Company's satisfaction that the specific days are not similar days. The Company and Customer may mutually agree to use an alternate method to determine Baseline Usage when the Customer's usage is highly variable.

LOAD REDUCTION DETERMINATION

During an Emergency Curtailment, the individual Customer or group of Customers will be required to reduce Baseline Usage to a Company-determined Maximum Circuit Load (MCL). The MCL is the Customer's or group of Customer's Baseline Usage minus the necessary load reduction of 5, 10, or 15%.

SCHEDULE 88 (Continued)

LOAD REDUCTION DETERMINATION (Continued)

The Company may choose at any time during an Emergency Curtailment to increase the load reduction percentage. Upon notification of an MCL change, the Customer/Lead Customer has one-half hour (30 minutes) to meet the new MCL. The Company may only make one notification of an increased increment of reduction per hour.

If the Customer is participating in Demand Buy Back Rider (Schedule 86), Baseline Usage will be determined after subtracting the Buy Back amount stipulated under that schedule. State mandated curtailments as defined under Rule N will also be subtracted before determining Baseline Usage.

LOAD REDUCTION PLAN

Participation depends upon the Company approval of a single submitted Load Reduction Plan. A renewed plan is due annually on March 15th.

A Lead Customer will submit one Load Reduction Plan for the group of Customers served on the same dedicated primary circuit and jointly participating. The Lead Customer assumes responsibility for submitting the group's Load Reduction Plan, managing the load reduction and paying all noncompliance charges.

The Load Reduction Plan must include the following:

1) Customer or Lead Customer's name;
2) A list of all other participating Customers, their account numbers, service and mailing addresses, and contact information;
3) The Customer or Lead Customer's alphanumeric pager and facsimile numbers to be used for notification of an Emergency Curtailment;
4) A Company and Customer mutually agreed upon Baseline Usage;
5) An estimated MCL for the 5, 10, and 15% load reduction levels. The MCL for the 5% load reduction is equal to the Baseline Usage times 0.95; 10% load reduction is Baseline Usage times 0.90; 15% reduction is Baseline Usage times 0.85; and
6) Specific quantifiable measures to be utilized by the Customer to reduce load to or below each MCL.

NOTIFICATION

The Company will notify the Customer/Lead Customer as to the percent of load reduction needed by alphanumeric pager and/or facsimile. The Customer/Lead Customer is responsible for keeping the pager and facsimile functioning and able to receive notification.

SCHEDULE 88 (Continued)

NOTIFICATION (Continued)

Upon notification, the Lead Customer will be responsible for contacting all other Customers participating under that plan. Upon notification, the Customer/Lead Customer will have 30 minutes to establish the determined MCL.

METERING EQUIPMENT

Customers on a dedicated circuit with one SP will have load reduction compliance audited by an interval meter with remote access capacity. The Company will install metering that records usage in 15-minute intervals. The Customer will provide communication service to the meter if requested by the Company. Participation under this schedule is subject to meter availability.

Customers on a dedicated circuit with more than one SP will have compliance monitored from individual meters or electronic recording equipment located at Company substations. Where the circuit does not have electronic recording equipment to monitor its load, the Company will install such equipment subject to availability. The Customer/Lead Customer will provide communication service when requested by the Company.

A Customer/Lead Customer will not be allowed to participate in any Load Reduction Programs until the proper monitoring equipment is installed and operational.

FAILURE TO COMPLY

Failure to meet the required MCL, to maintain the MCL for the duration of the Emergency Curtailment or to meet the required MCL within the required 30 minutes after notification will result in a noncompliance penalty. The penalty is equal to two times the baseline circuit load (BCL) on the applicable circuit, less the required MCL by hour, times the market price (MP) for power during the Emergency Curtailment as determined by an appropriate index such as the Intercontinental Exchange Mid-Columbia Daily Electricity Firm Price Index:

$$\text{Penalty} = 2[MP(BCL - MCL)]$$

Such penalties will be in addition to all other Company charges for Electricity Service.

After two noncompliance penalties, the Customer/Lead Customer will be removed from the program. Failure to pay noncompliance penalties may result in the termination of the Customer's/Lead Customer's Electricity Service.

SCHEDULE 88 (Concluded)

ADJUSTMENTS

Supplemental adjustment schedules are applicable to the Customer's underlying rate schedule and not applicable to this schedule unless approved by the Commission.

SPECIAL CONDITIONS

1. The Company may not be able to supply advance notice of an Emergency Curtailment. Participation in this program does not guarantee that the Customer or group of Customers will not be subject to outages related to maintenance, storms or system emergencies caused by natural catastrophes.

2. The Company is not liable for any damage to Customer's property resulting from participation in this program.

TERM

Service under this schedule will be for a term of one year. Service thereafter may be extended after Company review of Customer's/Lead Customer's annually updated Load Reduction Plan. Customer/Lead Customer's decision to leave the program at any time may limit its eligibility to participate in the program in the future.

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	$4,950.00	$4,900.00	$6,440.00
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$2.45	$2.42	$2.38
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.61	$1.59	$1.59
Over 4,000 kW	$1.30	$1.28	$1.28
per kW of monthly On-Peak Demand	$1.56	$1.54	$0.12
Energy Charge (per kWh)			
On-Peak Period***	7.358 ¢	7.285 ¢	7.210 ¢
Off-Peak Period***	5.858¢	5.785 ¢	5.710 ¢
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.205 ¢	0.203 ¢	0.201 ¢

* 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 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 0.314¢ 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.

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 89 (Continued)

ELECTION WINDOWS

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

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and Subtransmission voltage service respectively.

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 89 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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 RATE

The sum of the following charges per Service Point (SP)*:

	Delivery Voltage	
	Primary	Subtransmission
Basic Charge	$20,300.00	$20,300.00
Transmission and Related Services Charge per kW of monthly On-Peak Demand	$2.42	$2.38
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.75	$1.75
Over 4,000 kW	$1.44	$1.44
per kW of monthly on-peak Demand	$1.54	$0.12
Energy Charge (per kWh)		
Usage (30MWa – 250MWa)		
On-Peak Period***	7.148¢	7.068¢
Off-Peak Period***	5.606¢	5.526¢
Usage (greater than 250MWa)		
On-Peak Period***	6.954¢	6.876¢
Off-Peak Period***	5.454¢	5.376¢
System Usage Charge		
Usage (30MWa – 250MWa) per kWh	0.190¢	0.188¢
Usage (greater than 250MWa) per kWh	0.185¢	0.183¢

* 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 0.314¢ 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.

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 (Continued)

ELECTION WINDOWS

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

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and Subtransmission voltage service respectively.

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 90 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 91
STREET AND HIGHWAY LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity generally are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services [1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs [(1)], in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to this Schedule.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)

Option B – Luminaire:

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable.

Without obligation or notice to the Customer, following actual knowledge of an inoperable luminaire, the company will attempt to repair the photocell as soon as reasonably possible; if PGE does not possess the parts necessary for repair, PGE will replace inoperable luminaires with the equivalent LED luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services (1) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of certain failed parts including the lamp, power door (if applicable), photoelectric controller, starter and lens. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company's schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Option B Luminaire Maintenance (Continued)

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company.

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

3. The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given.

SCHEDULE 91 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

Option A provides for Company purchased and owned streetlight poles at the applicable rate.

Pole Maintenance under Option A

Maintenance of Option A poles includes straightening of leaning poles, the replacement of rotted wood poles no longer structurally sound or any pole, which by definition, has reached its natural end of life at no additional charge to the customer. Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles.

Emergency Pole Replacement and Repair

The Company will repair or replace structurally unsound poles 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 and subject to the Company's operating schedules and requirements and at no additional charge to the Customer.

Option B - Poles

Option B provides for Customer purchased and owned streetlight poles. The Company does not, at any time, assume ownership of Option B streetlight poles.

Maintenance Service under Option B

The Company provides for maintenance only as defined herein to Customer purchased and owned poles and related equipment at the applicable monthly Option B rate and subject to the Company’s operating schedules and requirements.

Maintenance of Option B poles includes straightening of leaning poles.

Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles, nor does maintenance of Option B poles include replacement of rotted wood poles no longer structurally sound, or any pole which by definition has reached its natural end of life.

SCHEDULE 91 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Upon Customer request, the Company may install and replace Option B poles at their discretion that have reached their natural end of life. All costs associated to the installation and removal of any pole is the sole responsibility of the Customer, in addition to the applicable monthly Option B rate.

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.

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	0.453 ¢ per kWh
Distribution Charge	6.231 ¢ per kWh
Energy Charge	
Cost of Service Option	6.047 ¢ per kWh

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 0.314¢ 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. 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)

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

Enrollment for 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

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime [(1)]
	$126.00 per hour	$161.00 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.

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	*	$0.99
	200	22,000	79	*	1.03
	400	50,000	163	*	1.05
Cobrahead	70	6,300	30	$6.16	1.29
	100	9,500	43	5.29	1.19
	150	16,000	62	*	1.20
	200	22,000	79	5.89	1.26
	250	29,000	102	5.43	1.21
	400	50,000	163	5.65	1.23
Flood	250	29,000	102	7.46	1.43
	400	50,000	163	7.46	1.43
Early American Post-Top	100	9,500	43	6.88	1.38
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	5.91	1.27
	100	9,500	43	*	1.34
	150	16,000	62	*	1.39

* 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	$5.52	$0.18
Fiberglass, Black or Bronze	30	8.98	0.30
Fiberglass, Gray	30	8.98	0.30
Fiberglass, Smooth, Black or Bronze	18	5.88	0.19
Fiberglass, Regular Black, Bronze, or Gray	18	4.97	0.16
	35	8.74	0.29
Aluminum, Regular with Breakaway Base	35	17.94	0.59
Aluminum, Smooth, Black, Pendant	23	18.31	0.60

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	$6.70	$0.22
Wood, Standard	40 to 55	7.87	0.26

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	$11.38	$1.90
HADCO Victorian, HPS	150	16,000	62	11.39	1.91
	200	22,000	79	9.81	1.73
	250	29,000	102	9.73	1.72
HADCO Capitol Acorn, HPS	100	9,500	43	13.87	2.19
	150	16,000	62	*	2.14
	200	22,000	79	*	2.22
Special Architectural Types					
HADCO Independence, HPS	100	9,500	43	*	1.82
	150	16,000	62	*	*
HADCO Techtra, HPS	100	9,500	43	*	2.63
	150	16,000	62	18.92	2.73
	250	29,000	102	*	2.63
HADCO Westbrooke, HPS	70	6,300	30	13.01	2.06
	100	9,500	43	13.29	2.09
	150	16,000	62	*	2.43
	200	22,000	79	*	1.09
	250	29,000	102	11.66	1.90

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Special Types					
Flood, HPS	750	105,000	285	$10.88	*
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	$9.49	$0.31
	30	10.87	0.36
	35	12.57	0.41
Aluminum Davit	25	10.12	0.33
	30	11.37	0.38
	35	12.99	0.43
	40	16.67	0.55
Aluminum Double Davit	30	12.61	0.42

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Aluminum, Fluted Ornamental	14	$8.95	$0.30
Aluminum, Smooth Techtra Ornamental	18	19.12	0.63
Aluminum, Fluted Ornamental	16	9.29	0.31
Aluminum, Double-Arm, Smooth Ornamental	25	15.08	0.50
Aluminum, Fluted Westbrooke	18	17.98	0.59
Aluminum, Non-Fluted Ornamental, Pendant	18	17.87	0.59
Fiberglass, Fluted Ornamental Black	14	11.80	0.39
Fiberglass, Anchor Base, Gray or Black	35	11.89	0.39
Fiberglass, Anchor Base (Color may vary)	25	10.61	0.35
	30	12.94	0.43

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
Cobrahead, Metal Halide	150	10,000	60	*	*
Cobrahead, Mercury Vapor	100	4,000	39	*	*
	175	7,000	66	$5.13	$1.18
	250	10,000	94	*	*
	400	21,000	147	5.35	1.22
	1,000	55,000	374	5.98	1.33
Holophane Mongoose, HPS	150	16,000	62	*	1.99
	250	29,000	102	*	2.02
Special Box Similar to GE "Space-Glo"					
HPS	70	6,300	30	5.77	*
Mercury Vapor	175	7,000	66	5.75	1.27

* 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
Special Box, Anodized Aluminum					
Similar to GardCo Hub					
HPS	70	6,300	30	*	*
	100	9,500	43	*	$1.57
	150	16,000	62	*	*
	250	29,000	102	*	*
Metal Halide	250	20,500	99	*	1.04
	400	40,000	156	*	1.04
Cobrahead, Metal Halide	175	12,000	71	*	*
Flood, Metal Halide	400	40,000	156	$5.89	*
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	*	*
Special Architectural Types					
KIM SBC Shoebox, HPS	150	16,000	62	*	1.03
KIM Archetype, HPS	250	29,000	102	*	2.04
	400	50,000	163	*	2.44
Special Acorn-Type, HPS	70	6,300	30	8.48	1.64
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	Monthly Rates Option B
Early American Post-Top, HPS					
Black	70	6,300	30	$4.96	$1.17
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	5.37	1.21
Flood, HPS	70	6,300	30	5.42	*
	100	9,500	43	5.18	1.19
	200	22,000	79	5.81	1.28
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	$5.06	*
Aluminum, Painted Ornamental	35	*	$0.43
Aluminum, Regular	16	5.12	0.17
Concrete, Ornamental	35 or less	9.38	0.31
Fiberglass, Direct Bury with Shroud	18	7.51	0.25
Steel, Painted Regular **	25	9.38	0.31
Steel, Painted Regular **	30	10.72	0.35
Steel, Unpainted 6-foot Mast Arm **	30	*	0.35
Steel, Unpainted 8-foot Mast Arm **	35	*	0.43
Wood, Laminated without Mast Arm	20	*	0.18
Wood, Curved Laminated	30	*	0.25
Wood, Painted Underground	35	6.63	0.22

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SCHEDULE 91 (Continued)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Company may offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one-year at which time the lighting service equipment will either be removed at Customer expense or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer’s selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer’s request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

SCHEDULE 91 (Continued)

SPECIAL CONDITIONS (Continued)

6. For Option C lights: The Company does not provide the circuit on new Option C installations.

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimated usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A “Qualified Worker” means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a “qualified person” or “qualified employee” with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

10. Indemnification:

    a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

SCHEDULE 91 (Continued)

SPECIAL CONDITIONS (Continued)

b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer.

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

SCHEDULE 91 (Concluded)

SPECIAL CONDITIONS (Continued)

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

TERM

A Customer served under the Daily Pricing option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made.

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	0.489	¢ per kWh
Distribution Charge	1.861	¢ per kWh
Energy Charge	6.617	¢ per kWh

* 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 92 (Concluded)

ELECTION WINDOW (Continued)

November Election Window

Enrollment for 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

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

The Customer will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

1. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

2. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule, using sampling techniques to determine whether in the Company's opinion the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Electricity use as it may deem to be satisfactory or discontinue service to the Customer under this schedule.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 95
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments for lighting service utilizing Company approved new technology streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity generally are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option A (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs(1), in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services(2) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to this Schedule.
(2) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option B (Continued)

Maintenance under Option B luminaires specifically does not include replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

Emergency Luminaire Replacement and Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable.

Without obligation or notice to the Customer, luminaire repair or replacement shall occur as soon as reasonably possible subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE’s Customer Service or PGE’s Outdoor Lighting Services(1) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of the photoelectric controller. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company’s schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

(1) Contact PGE’s Outdoor Lighting Services at 503-736-5710, PGE’s Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Option B Luminaire Maintenance (Continued)

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on non-Company owned poles or Company-owned distribution poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company.

Maintenance Service under Option C

The Company has no obligation to maintain Customer-purchased lighting if the Customer selects this option. Such maintenance and service is the sole responsibility of the Customer.

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

1. If Customer elects to convert any of its luminaires from Schedule 91/95 Option B to Schedule 95 Option C, the Customer must at the same time commit to convert the entirety of Customer’s Schedule 91/95 Option B luminaires to Schedules 91 Option C and Schedule 95 Option C using one of two methods: (A) within five years following PGE’s group lamp replacement cycle or (B) within three years on a schedule mutually agreed upon between the Company and Customer. Customer may elect to have some of its luminaires on Schedule 91 Option C and some on Schedule 95 Option C.

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	0.453 ¢ per kWh
Distribution Charge	6.231 ¢ per kWh
Energy Charge	
Cost of Service Option	6.047 ¢ per kWh

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 0.314¢ 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. 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)

NON-COST OF SERVICE OPTION (Continued)

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.

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 Balance-of-Year Election 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. The move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to either the Cost of Service or Daily Price Option during the Balance-of-Year Election Window.

November Election Window

Enrollment for 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 Enrollment Windows will remain open until 5:00 p.m. 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 to eligible service options using the Company's website, https://portlandgeneral.com

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime
	$126.00 per hour	$161.00 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.

		Nominal	Monthly	Monthly Rates	
Type of Light	Watts	Lumens	kWh	Option A	Option B
Roadway LED	>20-25	3,000	8	$5.17	$0.42
	>25-30	3,470	9	5.17	0.42
	>30-35	2,530	11	5.54	0.43
	>35-40	4,245	13	5.17	0.42
	>40-45	5,020	15	5.35	0.43
	>45-50	3,162	16	5.39	0.43
	>50-55	3,757	18	5.67	0.43
	>55-60	4,845	20	5.35	0.43
	>60-65	4,700	21	5.35	0.43
	>65-70	5,050	23	6.07	0.44
	>70-75	7,640	25	6.09	0.44
	>75-80	8,935	26	6.09	0.44
	>80-85	9,582	28	6.09	0.44
	>85-90	10,230	30	6.09	0.44
	>90-95	9,928	32	6.09	0.44
	>95-100	11,719	33	6.09	0.44
	>100-110	7,444	36	6.31	0.45
	>110-120	12,340	39	6.09	0.44
	>120-130	13,270	43	6.09	0.44
	>130-140	14,200	46	7.04	0.46
	>140-150	15,250	50	8.39	0.49
	>150-160	16,300	53	8.39	0.49
	>160-170	17,300	56	8.39	0.49
	>170-180	18,300	60	8.30	0.49
	>180-190	19,850	63	8.39	0.49
	>190-200	21,400	67	8.26	0.49

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	$13.32	$0.59
	>40-45	3,500	15	13.32	0.59
	>45-50	5,488	16	10.77	0.54
	>50-55	4,000	18	13.32	0.59
	>55-60	4,213	20	13.32	0.59
	>60-65	4,273	21	13.32	0.59
	>65-70	4,332	23	12.93	0.58
	>70-75	4,897	25	13.32	0.59
HADCO LED	70	5,120	24	17.42	0.67
Pendant LED (Non-Flared)	36	3,369	12	15.08	0.62
	53	5,079	18	16.33	0.65
	69	6,661	24	16.07	0.64
	85	8,153	29	16.69	0.66
Pendant LED (Flared)	>35-40	3,369	13	14.67	0.62
	>40-45	3,797	15	14.67	0.62
	>45-50	4,438	16	14.67	0.62
	>50-55	5,079	18	17.49	0.67
	>55-60	5,475	20	17.49	0.67
	>60-65	6,068	21	17.49	0.67
	>65-70	6,661	23	16.58	0.65
	>70-75	7,034	25	16.58	0.65
	>75-80	7,594	26	16.81	0.66
	>80-85	8,153	28	16.81	0.66
Post-Top, American Revolution					
LED	>30-35	3,395	11	8.12	0.48
	>45-50	4,409	16	8.12	0.48
Flood LED	>80-85	10,530	28	7.37	0.47
	>120-130	16,932	43	7.92	0.48
	>180-190	23,797	63	9.15	0.50
	>370-380	48,020	127	13.66	0.60

SCHEDULE 95 (Continued)

Light-Emitting Diode (LED) Only – Option C Energy Use

Type of Light	Watts*	Monthly kWh**
LED	5 - 10	3
LED	>10 - 15	4
LED	>15 - 20	6
LED	>20 - 25	8
LED	>25 - 30	9
LED	>30 - 35	11
LED	>35 - 40	13
LED	>40 - 45	15
LED	>45 - 50	16
LED	>50 - 55	18
LED	>55 - 60	20
LED	>60 - 65	21
LED	>65 - 70	23
LED	>70 - 75	25
LED	>75 - 80	26
LED	>80 - 85	28
LED	>85 - 90	30
LED	>90 - 95	32
LED	>95 - 100	33
LED	>100 - 110	36
LED	>110 - 120	39
LED	>120 - 130	43
LED	>130 - 140	46
LED	>140 - 150	50
LED	>150 - 160	53
LED	>160 - 170	56

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

SCHEDULE 95 (Continued)

Light-Emitting Diode (LED) Only – Option C Energy Use (Continued)

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 95 (Continued)

SPECIAL CONDITIONS

1. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

2. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

3. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer’s selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

4. If circuits or poles not already covered under Special Conditions 2 or 3 are removed or relocated at the Customer’s request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

5. For Option C lights: The Company does not provide the circuit on new installations.

6. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

7. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A “Qualified Worker” means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a “qualified person” or “qualified employee” with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 95 (Continued)

SPECIAL CONDITIONS (Continued)

8. Indemnification:

   a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

   b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

   c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 8.c. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer.

SCHEDULE 95 (Continued)

SPECIAL CONDITIONS (Continued)

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

9. The conversion of existing Schedule 91 luminaires to Schedule 95 Option A luminaires is subject to the Company's operating schedule.

SCHEDULE 95 (Concluded)

SPECIAL CONDITIONS (Continued)

10. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

11. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

TERM

A Customer served under the Daily Pricing Option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made.

SCHEDULE 99
SPECIAL CONTRACTS

PURPOSE

This schedule describes contracts between the Company and Customers at rates other than those contained in standard schedules. These descriptions do not include all terms and conditions in the contracts and are intended only as summaries. If there are any conflicts between these summaries and provisions in the contracts, the contracts will be controlling. The Company maintains for public inspection copies of special contracts at offices where the Tariff is available.

APPLICABLE

To those Customers that can meet the eligibility criteria established in Commission Order 87-402 and ORS 757.230, as well as the eligibility criteria listed below.

CONTRACTS

Port of Portland/Cascade General, Inc. (Portland)

Effective Date

February 21, 1996.

Term

Effective as long as Customer purchases Electricity Service under a mutually agreed to Tariff.

Rate

Schedule 89 - Large Nonresidential Standard Service (>4,000 kW)

Special Conditions

Customer to supply Electricity for resale to his/her "Customers" at his/her Repair Facility. Customer will be allowed to reflect charges over and above the Company's price for electricity in order to recover the costs of the Customer's electrical distribution system as outlined in the Portland Ship Repair Yard Price Schedule. As a result, bills received by his/her "Customers" may show a kWh charge above that which is charged by the Company.

Eligibility Criteria

1. Customer engaged in sales for resale prior to November 5, 1973.

2. Customer has significant investment in distribution facilities requiring additional cost recovery from its "Customers".

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules.

Schs.	102[1]	103[3]	105	106[1]	108[3]	109[1]	110[1]	115	118	122	123[1]	125[1]	126	128[4]	129[1]
7	x	x	x	x	x	x	x	x	x	x	x	x	x		
15	x	x	x	x	x	x	x	x	x	x	x	x	x		
32	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
38	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
47	x	x	x	x	x	x	x	x	x	x	x	x	x		
49	x	x	x	x	x	x	x	x	x	x	x	x	x		
75	x[2]	x	x[2]	x	x	x[2]	x[2]	x	x	x[2]	x	x[2]	x[2]	x	
76	x	x		x	x			x	x						
83	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
85	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
89	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
90	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
91		x	x	x	x	x	x	x	x	x	x	x	x	x	
92		x	x	x	x	x	x	x	x	x	x	x	x		
95		x	x	x	x	x	x	x	x	x	x	x	x	x	
485	x	x	x	x	x	x	x	x	x		x		x[5]		x
489	x	x	x	x	x	x	x	x	x		x		x[5]		x
490	x	x	x	x	x	x	x	x	x		x		x		x
491		x	x	x	x	x	x	x	x		x		x		x
492		x	x	x	x	x	x	x	x		x		x		x
495		x	x	x	x	x	x	x	x		x		x		x
515	x	x	x	x	x	x	x	x	x		x		x[5]	x	
532	x	x	x	x	x	x	x	x	x		x		x[5]	x	
538	x	x	x	x	x	x	x	x	x		x		x[5]	x	
549	x	x	x	x	x	x	x	x	x		x		x[5]	x	
575	x[2]	x	x[2]	x	x	x	x	x	x		x		x[2]	x	
576	x	x		x	x			x	x						
583	x	x	x	x	x	x	x	x	x		x		x[5]	x	
585	x	x	x	x	x	x	x	x	x		x		x[5]	x	
589	x	x	x	x	x	x	x	x	x		x		x[5]	x	
590	x	x	x	x	x	x	x	x	x		x		x	x	
591		x	x	x	x	x	x	x	x		x		x[5]	x	
592		x	x	x	x	x	x	x	x		x		x[5]	x	
595		x	x	x	x	x	x	x	x		x		x[5]	x	
689	x	x	x	x	x	x	x	x	x		x				

1. Where applicable.
2. These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
3. Schedule 108 applies to the sum of all charges less taxes, Schedule 109 and 115 charges and one-time charges such as deposits.
4. Applicable to Nonresidential Customer who receive service at Daily pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 485, 489, 490, 491, 492 and 495).
5. Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 100 (Concluded)

SUMMARY OF APPLICABLE ADJUSTMENTS (Continued)

Schs.	131	134	135	136	137	138	139	142	143	145	146	149	150	152
7	x	x	x	x	x	x		x	x	x	x	x	x	x
15	x	x	x	x	x	x		x	x	x	x	x	x	x
32	x	x	x	x	x	x		x	x	x	x	x	x	x
38	x	x	x	x	x	x		x	x	x	x	x	x	x
47	x	x	x	x	x	x		x	x	x	x	x	x	x
49	x	x	x	x	x	x		x	x	x	x	x	x	x
75	x	x	x	x	x	x		x	x	x	x	x	x	x
76	x	x						x				x		
83	x	x	x	x	x	x		x	x	x	x	x	x	x
85	x	x	x	x	x	x		x	x	x	x	x	x	x
89	x	x	x	x	x	x		x	x	x	x	x	x	x
90	x	x	x	x	x	x		x	x	x	x	x	x	x
91	x	x	x	x	x	x		x	x	x	x	x	x	x
92	x	x	x	x	x	x		x	x	x	x	x	x	x
95	x	x	x	x	x	x		x	x	x	x	x	x	x
485	x	x			x	x		x	x			x	x	x
489	x	x			x	x		x	x			x	x	x
490	x	x			x	x		x	x			x	x	x
491	x	x			x	x		x	x			x	x	x
492	x	x			x	x		x	x			x	x	x
495	x	x			x	x		x	x			x	x	x
515	x	x	x	x	x	x		x	x	x	x	x	x	x
532	x	x	x	x	x	x		x	x	x	x	x	x	x
538	x	x	x	x	x	x		x	x	x	x	x	x	x
549	x	x	x	x	x	x		x	x	x	x	x	x	x
575	x	x	x	x	x	x		x	x	x	x	x	x	x
576	x	x						x				x		
583	x	x	x	x	x	x		x	x	x	x	x	x	x
585	x	x	x	x	x	x		x	x	x	x	x	x	x
589	x	x	x	x	x	x		x	x	x	x	x	x	x
590	x	x	x	x	x	x		x	x	x	x	x	x	x
591	x	x	x	x	x	x		x	x	x	x	x	x	x
592	x	x	x	x	x	x		x	x	x	x	x	x	x
595	x	x	x	x	x	x		x	x	x	x	x	x	x
689	x	x		x	x	x	x	x	x			x	x	x

6. Where applicable.
7. These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
8. Schedule 108 applies to the sum of all charges less taxes, Schedule 109 and 115 charges and one-time charges such as deposits.
9. Applicable to Nonresidential Customer who receive service at Daily pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 485, 489, 490, 491, 492 and 495).
10. Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 102
REGIONAL POWER ACT EXCHANGE* CREDIT

PURPOSE

Each Customer's bill rendered under schedules providing Residential Service, Farm Service and Nonresidential Farm Irrigation and Drainage Pumping Service will include the Regional Power Act Exchange Credit applied to each kWh sold when the Customer qualifies for the adjustment according to the definitions and limitations set forth in this schedule. Where Customers are served by Electricity Service Suppliers (ESSs), the ESS will agree to pass through the credit to the Customer.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Direct Access Service, Emergency Default Service, Standard Service and Residential Service where the Customer meets the definition of Residential Service, Farm Service or Farm Irrigation and Drainage Pumping Service as specified in this schedule. Consistent with the requirements of the Bonneville Power Administration (BPA), if, in the course of doing business, a utility discovers that one of its existing Customers is growing Cannabis using power provided by the utility, such customer is not eligible for the Regional Power Act Exchange Credit under this Schedule.

REGIONAL POWER ACT EXHANGE CREDIT

The credit will be the value of power and other benefits inclusive provided in accordance with the terms of the Settlement Agreement between the Company and the BPA.

The credit inclusive of interest is:

All schedules	(0.676) ¢ per kWh

RESIDENTIAL SERVICE

Residential Service means Electricity Service provided for residential purposes including service to master-metered apartments, apartment utility rooms, common areas, and other residential uses.

* Short title for "Pacific Northwest Electric Power Planning and Conservation Act".

SCHEDULE 102 (Concluded)

FARM IRRIGATION AND DRAINAGE PUMPING SERIVE

Farm Irrigation and Drainage Pumping Service means Electricity Service to a parcel of land used for the raising of crops, livestock, or pasturage and includes service to irrigation pumps.

FARM SERVICE

Farm Service means Electricity Service furnished to Premises employed for the purpose of obtaining a profit in money by raising, harvesting and selling crops; or by the feeding, breeding, management and sale of, or the produce of, livestock, poultry, fur-bearing animals, or honeybees; or for dairying and the sale of dairy products; or any other agricultural or horticultural use, animal husbandry, or any combination thereof. Farm Service includes the use of Energy to prepare and store the products raised on the Premises for human use and animal use and his/her disposal by marketing or otherwise. Farm Service does not include the use of Energy for commercial treatment, storage, or distribution of agricultural or horticultural products and does not include the use of land subject to the provisions of ORS Chapter 321 concerning commercial forestry.

SPECIAL CONDITIONS

1. The Credit will be applied to residential and farm usage; however, irrigation for farm use is limited to the first 400 horsepower per farm. The 400-horsepower limitation will be converted to maximum monthly kWh usage according to the following formula:

   400 hp x .746 x (24 hrs x days in Billing Period) = maximum kWh but not to exceed 222,000 kWh in any month

2. The credit is no longer applicable upon determination that the service no longer constitutes residential or farm usage. The Customer or ESS will notify the Company of any change of the type of service on the Customer's Premises. The credit and eligibility for the adjustment are subject to review and approval by BPA and the Commission.

SCHEDULE 103
METRO SUPPORTIVE HOUSING SERVICES BUSINESS INCOME TAX RECOVERY

PURPOSE

To recover from Customers inside Metro's jurisdiction in Clackamas, Multnomah and Washington Counties the Metro Supportive Housing Services (MSHS) Business Income Tax paid by the Company in accordance with Measure 26-210 OAR 860-022-0045 and to establish an associated Automatic Adjustment Clause and balancing account.

APPLICABLE

All Customers receiving Electricity Service within Metro's jurisdiction in Clackamas, Multnomah and Washington Counties.

BALANCING ACCOUNT

The MSHS Balancing Account will be maintained to accrue any difference between the Company's actual local income 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 Metro Supportive Housing Services Rate is established. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts.

METRO SUPPORTIVE HOUSING SERVICES RATE DETERMINATION

The MSHS Rate is determined by dividing the sum of forecast MSHS tax liability plus or minus any amount in the Balancing Account divided by forecast Retail Revenue from Customers in Metro's jurisdiction in Clackamas, Multnomah or Washington Counties for each tax year or other applicable recovery period.

MSHS RATE

The MSHS Rate is:

> 0.024% of the total billed amount to the Customer excluding the Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes.

SCHEDULE 105
REGULATORY ADJUSTMENTS

PURPOSE

The purpose of this schedule is to reflect the effects of regulatory adjustments such as net gains from nonrecurring property transactions, and costs associated with the implementation of SB 1149, and miscellaneous nonrecurring items.

APPLICABLE

To all bills for Electricity Service calculated under all schedules and contracts, except those Customers explicitly exempted.

PART A – MISCELLANEOUS ADJUSTMENTS

Part A will be adjusted annually as necessary to recover nonrecurring Regulatory Adjustments.

PART B – LARGE NON-RESIDENTIAL LOAD TRUE-UP

Part B consists of costs associated with the Schedule 128 Large Nonresidential Load Shift True-up after the November annual open enrollment window.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Part A	Part B	Adjustment Rate	
7	0.016	0.000	0.016	¢ per kWh
15/515	0.019	0.000	0.019	¢ per kWh
32/532	0.010	0.000	0.010	¢ per kWh
38/538	0.010	0.009	0.019	¢ per kWh
47	0.015	0.000	0.015	¢ per kWh
49/549	0.013	0.009	0.022	¢ per kWh
75/575				
Secondary	0.017	0.009	0.026	¢ per kWh(1)
Primary	0.017	0.009	0.026	¢ per kWh(1)
Subtransmission	0.017	0.009	0.026	¢ per kWh(1)
83/583	0.007	0.009	0.016	¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 105 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
85/585				
Secondary	0.006	0.009	0.015	¢ per kWh
Primary	0.006	0.009	0.015	¢ per kWh
89/589				
Secondary	0.017	0.009	0.026	¢ per kWh
Primary	0.017	0.009	0.026	¢ per kWh
Subtransmission	0.017	0.009	0.026	¢ per kWh
90/590				
Primary	0.016	0.009	0.025	¢ per kWh
Subtransmission	0.016	0.009	0.025	¢ per kWh
91/591	0.019	0.009	0.028	¢ per kWh
92/592	0.005	0.009	0.014	¢ per kWh
95/595	0.019	0.009	0.028	¢ per kWh
485				
Secondary	0.002	0.000	0.002	¢ per kWh
Primary	0.002	0.000	0.002	¢ per kWh
489				
Secondary	0.013	0.000	0.013	¢ per kWh
Primary	0.013	0.000	0.013	¢ per kWh
Subtransmission	0.013	0.000	0.013	¢ per kWh
490				
Primary	0.016	0.000	0.016	¢ per kWh
Subtransmission	0.016	0.000	0.016	¢ per kWh
491	0.019	0.000	0.019	¢ per kWh
492	0.005	0.000	0.005	¢ per kWh
495	0.019	0.000	0.019	¢ per kWh
689				
Secondary	0.013	0.000	0.013	¢ per kWh
Primary	0.013	0.000	0.013	¢ per kWh
Subtransmission	0.013	0.000	0.013	¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 106
MULTNOMAH COUNTY BUSINESS INCOME TAX RECOVERY

PURPOSE

To recover from Customers in Multnomah County the Multnomah County Business Income Tax (MCBIT) paid by the Company in accordance with Multnomah County Code § 12.610 and OAR 860-022-0045 and to establish an associated Automatic Adjustment Clause and balancing account.

APPLICABLE

All Customers receiving Electricity Service within Multnomah County.

BALANCING ACCOUNT

A MCBIT Balancing Account will be maintained to accrue any difference between the Company's actual local income 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 MCBIT Rate is established. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts.

MCBIT RATE DETERMINATION

The MCBIT Rate is determined by dividing the sum of forecast MCBIT tax liability plus or minus any amount in the Balancing Account divided by forecast Retail Revenue from Customers in Multnomah County for each tax year or other applicable recovery period.

MCBIT RATE

The MCBIT Rate is:

> 0.00% of the total billed amount to the Customer excluding the Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes.

SCHEDULE 108
PUBLIC PURPOSE CHARGE

PURPOSE

To collect funds associated with activities mandated for the benefit of the general public pursuant to OAR 860-038-0480. Activities include new energy, related investments in schools, new renewable energy resources and customer investments in technologies supporting reliability, resilience and the integration of renewable energy resources with the Company's distribution system, low-income housing resources and new low-income weatherization.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except Nonresidential Customers qualifying as a Self-Directing Customer may be partially exempt.

PUBLIC PURPOSE CHARGE

The Public Purpose Charge will be 1.5% of total revenue billed to the Customer "for electricity services, distribution, ancillary services, metering and billing, transition charges and other types of costs that were included in electric rates on July 23, 1999" as specified in OAR 860-038-0480(2).

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be a Self-Directing Customer (SDC), the Large Nonresidential Customer must have a load that exceeds one aMW and receive certification from the Oregon Department of Energy (ODOE) as an SDC. Beginning November 30, 2004, the Company will include the credits due, as reported by the ODOE, to the applicable portions of the SDCs monthly Public Purpose Charge.

SPECIAL CONDITIONS

1. Electricity Service Suppliers (ESS) – Each ESS that provides Direct Access Service in the Company's service territory will collect a Public Purpose Charge from its Direct Access Customers. The ESS will remit monthly to the Company the Public Purpose Charges it collects from Customers and provide calculations of the Public Purpose Charge for each Service Point enrolled in Direct Access. The ESS will supply the Company with this information, so the Company can correctly allocate the applicable portions of the Direct Access SDC's monthly Public Purpose Charge and ensure Disbursement of Funds collected are allocated as required.

SCHEDULE 108 (Concluded)

SPECIAL CONDITIONS (Continued)

2. Disbursement of Funds – The Company will distribute monthly, Public Purpose funds collected, minus reasonable administrative costs, as outlined in OAR 860-038-0480 and required by ORS 757.612:

   - The funds for energy related investments in schools to the education service districts located in the Company's service territory = 0.30% of revenues (20% of total);

   - The funds for renewable energy resources and customer investments in technologies supporting reliability, resilience, and the integration of renewable energy resources will be allocated as directed by the Commission = 0.51% of revenues (34% of total);

   - The funds for low-income weatherization will be allocated to the Housing and Community Services Department = 0.55% of revenues (36.67% of total); and

   - The funds for low-income housing will be allocated to the Housing and Community Services Department Revolving Account = 0.14% of revenues (9.33% of total).

TERM

This Schedule will terminate on January 1, 2036.

SCHEDULE 109
ENERGY EFFICIENCY FUNDING ADJUSTMENT

PURPOSE

To fund the acquisition of additional Energy Efficiency Measures (EEMs) for the benefit of the Company's Customers pursuant to ORS 757.054.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory. Nonresidential Customers whose load exceeded one aMW at a Service Point (SP) during the prior calendar year or those Nonresidential Customers qualifying as a Site certified by Oregon Department of Energy (ODOE) will not be charged an amount in rates that exceeds 1.7% of the total revenue received from the sale of electricity serviced to the Site from any source.

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the ODOE as a SDC. The Company will include the credits due, as reported by the ODOE, to the applicable portions of the SDCs monthly Schedule 109 Charge.

DISBURSEMENT OF FUNDS

All funds collected under this schedule less an allowance for uncollectible expenses will be distributed to the ETO on a monthly basis.

SCHEDULE 109 (Continued)

ENERGY EFFICIENCY ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:
Standard Pricing

Schedule	Adjustment Rate
7	0.579 ¢ per kWh
15/515	0.794 ¢ per kWh
32/532	0.576 ¢ per kWh
38/538	0.635 ¢ per kWh
47	0.922 ¢ per kWh
49/549	0.635 ¢ per kWh
75/575	
Secondary	0.125 ¢ per kWh
Primary	0.121 ¢ per kWh
Subtransmission	0.123 ¢ per kWh
83/583	0.464 ¢ per kWh
85/485/585	
Secondary	0.400 ¢ per kWh
Primary	0.413 ¢ per kWh
89/489/589/689	
Secondary	0.125 ¢ per kWh
Primary	0.121 ¢ per kWh
Subtransmission	0.123 ¢ per kWh
90/490/590	
Primary	0.113 ¢ per kWh
Subtransmission	0.113 ¢ per kWh
91/491/591	0.553 ¢ per kWh
92/492/592	0.409 ¢ per kWh
95/495/595	0.553 ¢ per kWh

SCHEDULE 109 (Concluded)

ENERGY EFFICIENCY ADJUSTMENT (Continued)

Over One Average Megawatt or Site Price Adjustment

Schedule	Adjustment Rate
15/515 >1aMW	0.140 ¢ per kWh
32/532 >1aMW	0.214 ¢ per kWh
38/538 >1aMW	0.243 ¢ per kWh
47 >1aMW	0.353 ¢ per kWh
49/549 >1aMW	0.243 ¢ per kWh
75/575 >1aMW	
Secondary	0.125 ¢ per kWh
Primary	0.121 ¢ per kWh
Subtransmission	0.123 ¢ per kWh
83/583 >1aMW	0.149 ¢ per kWh
85/485/585 >1aMW	
Secondary	0.132 ¢ per kWh
Primary	0.126 ¢ per kWh
89/489/589/689 >1aMW	
Secondary	0.125 ¢ per kWh
Primary	0.121 ¢ per kWh
Subtransmission	0.123 ¢ per kWh
90/490/590 >1aMW	
Primary	0.113 ¢ per kWh
Subtransmission	0.113 ¢ per kWh
91/491/591/95/495/595 >1aMW	0.223 ¢ per kWh

TERM

This Schedule will terminate on January 1, 2036.

SCHEDULE 110
ENERGY EFFICIENCY CUSTOMER SERVICE

PURPOSE

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Service Point (SP) during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer (SDC). Customers so exempted will not be charged the prices contained in this Schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

Energy Efficiency Measures (EEMs) – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the ODOE as a SDC.

BALANCING ACCOUNT

Effective June 1, 2010, the Company will establish a balancing account to record the differences between the actual fully loaded qualifying expenses (which may not exceed $1.3 million in any year) and the revenues collected under this schedule adjusted for allowance for uncollectibles, franchise fees, and other revenue sensitive costs. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

SCHEDULE 110 (Concluded)

ENERGY EFFICIENCY CUSTOMER SERVICE ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Adjustment Rate
7	0.004 ¢ per kWh
15/515	0.008 ¢ per kWh
32/532	0.004 ¢ per kWh
38/538	0.004 ¢ per kWh
47	0.007 ¢ per kWh
49/549	0.005 ¢ per kWh
75/575	
Secondary	0.003 ¢ per kWh
Primary	0.003 ¢ per kWh
Subtransmission	0.003 ¢ per kWh
83/583	0.003 ¢ per kWh
85/485/585	
Secondary	0.003 ¢ per kWh
Primary	0.003 ¢ per kWh
89/489/589/689	
Secondary	0.003 ¢ per kWh
Primary	0.003 ¢ per kWh
Subtransmission	0.003 ¢ per kWh
90/490/590	
Primary	0.003 ¢ per kWh
Subtransmission	0.003 ¢ per kWh
91/491/591	0.008 ¢ per kWh
92/492/591	0.002 ¢ per kWh
95/495/595	0.008 ¢ per kWh

SCHEDULE 115
LOW-INCOME ASSISTANCE

PURPOSE

The purpose of this rate schedule is to implement the low-income bill payment assistance provisions in accordance with ORS 757.612(7)(b) and reflective of adjustments made via House Bill 2739 (2021 regular session). The latter directs electric companies to collect an additional $10 million annually for two years, starting in 2022, bringing the statewide total to approximately $30 million annually.

APPLICABLE

To all Retail Electricity Customers, including Customers receiving electricity from other sources and Customers who do not purchase distribution services from PGE per ORS 757.612(8), except those Customers explicitly exempted.

ADJUSTMENT RATES

The applicable Adjustment Rates are listed below. As specified in House Bills 2134 and 2739, Customers will not be required to pay more than $500 per month per Site for low-income bill payment assistance.

Schedules	Adjustment Rate
7	$1.04 per month
All other Schedules, including DSIs	0.104¢ per kWh for the first 480,769 kWh

SPECIAL CONDITION

1. On a monthly basis, on or before the last day of the month, the Company will forward an amount to the Oregon Housing and Community Services Department (OHCS) based on billings to Customers for the previous month less a reserve for uncollectible amounts.

SCHEDULE 118
BILL ADJUSTMENT
COST RECOVERY MECHANISM

PURPOSE

The purpose of this schedule is to recover the costs associated with PGE's Income-Qualified Bill Discount, an offering to eligible Residential Customers designed to increase bill affordability (operationalized in Schedule 18). This discount is enabled by House Bill 2475 (2021 regular session), which calls for differentiated rates for "low-income customers and other economic, social equity or environmental justice factors that affect affordability for certain classes of utility customers." This adjustment schedule is implemented as an automatic adjustment clause as provided for in ORS 757.210.

APPLICABLE

To all bills for Electricity Service.

ADJUSTMENT RATES

The applicable Adjustment Rates are listed below. Customers will not be required to pay more than $1,000 per month per Site for cost recovery of the Income-Qualified Bill Discount.

Schedules	Adjustment Rate
7	$1.14 per bill
All other Schedules	0.114¢ per kWh for the first 877,193 kWh

SCHEDULE 122
RENEWABLE RESOURCES AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource and energy storage projects associated with renewable energy resources (including associated transmission) not otherwise included in rates. Additional new renewable and energy storage projects associated with renewable energy resources may be incorporated into this schedule as they are placed in service. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210 and Section 13 of the Oregon Renewable Energy Act (OREA).

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76, 485, 489, 490, 491, 492, 495, 576 and 689. This schedule is not applicable to direct access customers after December 31, 2010.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.000	¢ per kWh
15	0.000	¢ per kWh
32	0.000	¢ per kWh
38	0.000	¢ per kWh
47	0.000	¢ per kWh
49	0.000	¢ per kWh
75		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
83	0.000	¢ per kWh
85		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate	
89			
	Secondary	0.000	¢ per kWh
	Primary	0.000	¢ per kWh
	Subtransmission	0.000	¢ per kWh
90			
	Primary	0.000	¢ per kWh
	Subtransmission	0.000	¢ per kWh
91		0.000	¢ per kWh
92		0.000	¢ per kWh
95		0.000	¢ per kWh

ANNUAL REVENUE REQUIREMENTS

The Annual Revenue Requirements of a qualifying project will include the fixed costs of the renewable resource or energy storage project associated with renewable energy resources and associated transmission (including return on and return of the capital costs), operation and maintenance costs, income taxes, property taxes, and other fees and costs that are applicable to the renewable resource or energy storage project associated with renewable energy resources or associated transmission. Until the dispatch benefits are included in the Annual Power Cost Update Schedule 125, the net revenue requirements of each project (fixed costs less market value of the energy produced by the renewable resource or energy storage project associated with renewable energy resources plus any power costs such as fuel, integration and wheeling costs) will be included in the Schedule 122 rates. By no later than April 1 of each year following the resource’s on-line date, the Company will file an update to the revenue requirements of resources included in this schedule to recognize projected changes for the following calendar year. Should the final determination of a Schedule 122 filing for a new resource not allow for inclusion of its net variable power costs (NVPC) in the AUT, these will be included in the Schedule 122 revenue requirement used to set initial prices. In this circumstance, the resource’s NVPC impacts will subsequently be removed from Schedule 122 prices and included in the AUT at the next available opportunity.

The Company may file a deferral request based on the Annual Revenue Requirements if an automatic adjustment clause is not established prior to the resource’s on-line date, to be recovered through Schedule 122. The balancing account will accrue interest at the Commission-authorized rate for deferred accounts, and the amortization of the deferred amount will not be subject to the provisions of ORS 757.259(5).

SCHEDULE 122 (Continued)

TIME AND MANNER OF FILING

When the Company proposes to include a new resource under this schedule and, by no later than April 1 of each calendar year that the Company is required to update the Annual Revenue Requirements for an existing resource, the Company will file the following:

1. Revised rates under this schedule and a transmittal letter that summarizes the proposed revenue requirements and charges for both the new resource(s) and the updated revenue requirements and charges for applicable resources previously approved for recovery under this schedule. In addition, the filing will include revised income taxes and associated ratios to calculate “taxes authorized to be collected in rates” under ORS 757.268.

2. Within the Company’s Annual Power Cost Update (Schedule 125) filing, the Company will include for the following year the expected generation of resources included in this schedule and the power costs of these resources.

3. Work papers that support the calculation of revenue requirements for all applicable resources and demonstrate how the proposed prices are calculated.

With respect to a Schedule 122 rate change for the initial inclusion of the allowable costs of a new resource, and in compliance with the Commission’s findings in the proceeding(s) regarding the initial cost recovery of the new resource, the Company will file updated Schedule 122 rates by no less than 30 days prior to the rate effective date.

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule’s forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

2. Each renewable resource project (and associated transmission) included in this adjustment schedule must be separately identified and be a new resource defined as “renewable” in the OREA.

3. The costs for projects included under this schedule will be updated annually as provided above, and will continue to be recovered under Schedule 122 until such time as the costs are included in base rates or the project is no longer in service.

4. The in-service date for the new renewable resource project or energy storage project associated with renewable energy resources or each separately identifiable projectsegment will be verified by an attestation from the Company stating that the specific renewable resource project or energy storage project associated with renewable energy resources, or project segment, has met requirements for being commercially operational and is in service.

SCHEDULE 122 (Concluded)

SPECIAL CONDITIONS (Continued)

5. If the actual costs of an eligible new resource cannot be verified by the final round of testimony in the proceeding reviewing the filing for its initial cost recovery, the Company will include in its compliance filing for initial cost recovery an update to reflect then-currentactual resource costs, or forecasted costs where appropriate. If the updated costs are lower than the projected costs in the record of the proceeding, the update will contain sufficient information to support a reduction in the proposed adjustment charges before the effective date. If updated costs are higher than the projected costs in the proceeding'srecord or if actual costs cannot be verified prior to the compliance filing, the Company mayfile for deferred accounting under the OREA to allow an opportunity for recovery of the cost differences between the projected costs in the record and the prudently incurred actual costs. For purposes of Schedule 126 (Annual Power Cost Variance Mechanism), actual NVPC will be adjusted to remove the impact of any power produced by a new renewable resource or energy storage project associated with renewable energy resources qualifying for treatment under this schedule but not otherwise included in rates. The following adjustments will be made:

   a) Actual NVPC will be increased by the value of any renewable or energy storage resource energy. The value of such energy will be determined by employing the forward curves used to set rates for the year under the Annual Power Cost Update.Actual NVPC will be reduced by applicable fuel costs and supply integration costsfor the resource.

   b) Actual NVPC will also be increased or decreased as appropriate for any other credits or charges specifically identifiable with the new renewable or energy storage resource.

6. For Schedule 122 filings made on and after April 2009, the Commission may condition approval of a proposed change in Schedule 122 charges on PGE making a filing under ORS 757.210 within six months after the Commission order approving the proposed change. Through this filing, the Company will roll into the generation component of its rates all of the costs, or a portion thereof identified by the Commission, that are being collected through the then existing Schedule 122 charges. The Commission's order for conditional approval must be based upon: (1) a finding that the costs, or a portion thereof,specified by the Commission have been collected through Schedule 122 for a reasonableperiod of years, as determined by the Commission; or (2) for good cause, as determinedby the Commission.

SCHEDULE 123
DECOUPLING ADJUSTMENT

PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Service Point (SP) during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

Energy Efficiency Measures (EEMs) – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.

Self-Directing Customer (SDC) - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, differences between:

a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) to weather-normalized kWh Energy sales; and

b) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer to the numbers of active Customers for each applicable SNA rate schedule, respectively, for each month. For Schedule 7, a Secondary Fixed Charge equal to 69% of the Monthly Fixed Charge will be used to calculate Fixed Charge Revenues for actual customer counts that exceed the projected customer counts used to establish base rates in a general rate review.

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

The SNA will calculate monthly as the Fixed Charge Revenue less actual revenues and will accrue to the SNA Balancing Account. The monthly amount accrued may be positive (an under-collection) or negative (an over-collection). The SNA is divided into sub-accounts so that net accruals for each rate schedule will track separately.

The SNA is applicable to the following rate schedules:

Schedule	Fixed Charge Energy Rate (¢ per kWh)	Monthly Fixed Charge	Monthly Secondary Fixed Charge
7	8.870	$71.45	$49.30
32	7.693	$111.66	
83*	3.790	$790.34	

*Applicable beginning in 2019. The Fixed Charge Energy Rate for Schedule 83 includes fixed generation charges only.

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32, 83 (starting in 2019), and 532 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. Also included are differences in actual energy savings from a test year forecast associated with the conversion to LED streetlighting in Schedule 95 reported by the Company. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates.

The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are less than those estimated in setting base rates. A positive Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are greater than those estimated for the test year in setting base rates. The LRRA for each year subsequent to the test year will incorporate incremental kWh savings reported by the Energy Trust of Oregon for that year.

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA) (Continued)

For the purposes of this Schedule, the Lost Revenue Recovery Adjustment is the product of: (1) the reduction in kWh sales resulting from ETO-reported EEMs plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, and (2) the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule-weighted average of transmission, distribution, and fixed generation charges; including those contained in Schedule122 and other applicable schedules. System usage or distribution charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. Franchise fee recovery is not included in the Lost Revenue Rate. The applicable Lost Revenue Rate is 5.548 cents per kWh.

SNA and LRRA BALANCING ACCOUNTS

The Company will maintain a separate balancing account for the SNA applicable rate schedules and for the Nonresidential LRRA applicable rate schedules. Each balancing account will record over- and under-collections resulting from differences as determined, respectively, by the SNA and LRRA mechanisms. The accounts will accrue interest at the Commission-authorized Modified Blended Treasury Rate established for deferred accounts.

DECOUPLING ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate	
7	(0.222)	¢ per kWh
15/515	0.100	¢ per kWh
32/532	0.301	¢ per kWh
38/538	0.100	¢ per kWh
47	0.100	¢ per kWh
49/549	0.100	¢ per kWh
75/575		
Secondary	0.100	¢ per kWh
Primary	0.100	¢ per kWh
Subtransmission	0.100	¢ per kWh
83/583	0.088	¢ per kWh

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate
85/585	
Secondary	0.100 ¢ per kWh
Primary	0.100 ¢ per kWh
89/589	
Secondary	0.100 ¢ per kWh
Primary	0.100 ¢ per kWh
Subtransmission	0.100 ¢ per kWh
90/590	
Primary	0.100 ¢ per kWh
Subtransmission	0.100 ¢ per kWh
91/591	0.100 ¢ per kWh
92/592	0.100 ¢ per kWh
95/595	0.100 ¢ per kWh
485	
Secondary	0.017 ¢ per kWh
Primary	0.017 ¢ per kWh
489	
Secondary	0.017 ¢ per kWh
Primary	0.017 ¢ per kWh
Subtransmission	0.017 ¢ per kWh
490	
Primary	0.017 ¢ per kWh
Subtransmission	0.017 ¢ per kWh
491	0.017 ¢ per kWh
492	0.017 ¢ per kWh
495	0.017 ¢ per kWh
689	
Secondary	0.012 ¢ per kWh
Primary	0.012 ¢ per kWh
Subtransmission	0.012 ¢ per kWh

TIME AND MANNER OF FILING

Commencing in 2014, the Company will submit to the Commission the following information by November 1 of each year:

SCHEDULE 123 (Concluded)

TIME AND MANNER OF FILING (Continued)

1. The proposed price changes to this Schedule to be effective on January 1st of the subsequent year based on a) the amounts in the SNA Balancing Accounts and b) the amount in the LRRA Balancing Account.

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers detailing the calculation of the new proposed prices and the SNA weather-normalizing adjustments.

SPECIAL CONDITIONS

1. The Fixed Charge Energy Rate, Monthly Fixed Charge per Customer and the Lost Revenue Rate will be updated concurrently with a change in the applicable base revenues used to determine the rates.

2. Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that used for determining the forecasted loads used to establish base rates.

3. No revision to any SNA or LRRA Adjustment Rate will result in an estimated average annual rate increase greater than 2% to the applicable SNA or LRRA rate schedule, based on the net rates in effect on the effective date of the Schedule 123 rate revisions. Rate revisions resulting in a rate decrease are not subject to the 2% limit.

4. The LRRA prices for Customers served under the provisions of Schedules 485, 489, 490, 491, 492, 495 and 689 will be calculated to apply to distribution services only.

5. The SNA and LRRA mechanisms will terminate on May 8, 2022. Balances accrued up to that point will be subject to subsequent adjustment.

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an automatic adjustment clause as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 90, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91, and 95 are exempt from Schedule 125.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings, including, but not limited to:

- NVPC Modeling Enhancements, and new items
- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Wind energy forecast based on a five-year rolling average.
- Costs associated with wind integration. The battery portion of wind and solar projects that have a battery storage component may be included if the battery is charged solely by wind and solar generation.
- Dispatch of energy storage systems.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs.
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes.

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 1.0357.

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments and modeling enhancements 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 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, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the inal change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) new market power and fuel contracts entered into since the previous updates, 3) the final planned maintenance outages and load forecast from the October 1st filing, 4) final update to Qualifying Facilities online dates, and 5) final price for the energy generation at the Priest Rapids and Wanapum hydro facilities, as provided in the power contract between PGE and Grant County.

SCHEDULE 125 (Concluded)

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

ADJUSTMENT RATES

Schedule		¢ per kWh
7		0.000
15		0.000
32		0.000
38		0.000
47		0.000
49		0.000
75		
	Secondary	0.000 (1)
	Primary	0.000 (1)
	Subtransmission	0.000 (1)
83		0.000
85		
	Secondary	0.000
	Primary	0.000
89		
	Secondary	0.000
	Primary	0.000
	Subtransmission	0.000
90		
	Primary	0.000
	Subtransmission	0.000
91		0.000
92		0.000
95		0.000

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an automatic adjustment clause as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those who were served on Schedule 76R and 576R, 485, 489, 490, 491, 492, 495, 515, 532, 538, 549, 583, 585, 589, 591, 592, 595 and 689, or served under Schedules 83, 85, 89 or 90 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 590, 591, 592 and 595 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE

The Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance deviates from the Baseline Net Variable Power Cost (NVPC).

Forecast and Actual NVPC subject to the Annual Power Cost Variance Mechanism will exclude NVPC associated with Reliability Contingency Events.

RELIABILITY CONTINGENCY EVENT POWER COST VARIANCE

The Reliability Contingency Event (RCE) Power Cost Variance is the amount that the annual actual NVPC prudently incurred during RCEs deviates from forecast NVPC associated with RCEs. An RCE would qualify for 100% cost recovery or refund into the Power Cost Variance Account when an RCE is called as defined in this tariff.

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 Account.

SCHEDULE 126 (Continued)

POWER COST VARIANCE ACCOUNT (Continued)

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission but with a rolling amortization cap equivalent to 2.5% on an overall customer price basis. Additional amounts accrued beyond the 2.5% cap will be rolled over to subsequent period based on Commission approved amortization schedules including, but not limited to, offsetting of remaining amounts owed to the Company with credit amounts accrued to the Account in subsequent periods. 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 consistent with these concepts. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0357 to account for franchise fees, uncollectibles, and OPUC fees.

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will not be subject to an earnings review for the year that the power costs were incurred.

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 – RCE NVPC) / (Actual Loads – RCE Loads)

Annual Variance (AV) - The Annual Variance (AV) is the dollar amount calculated annually based on the following formula:

(Actual Unit NVPC – Adjusted Base Unit NVPC) * (Actual Loads – RCE Loads)

SCHEDULE 126 (Continued)

DEFINITIONS (Continued)

Base Unit NVPC - The Base Unit NVPC is the NVPC used to develop rate schedules for the applicable year divided by the associated calendar basis retail loads. Base NVPC are updated annually in accordance with Schedule 125.

Adjusted Base Unit NVPC - The Adjusted Base Unit NVPC is the NVPC used to calculate the Annual Variance. The Adjusted Base Unit NVPC is the Base Unit NVPC (determined in accordance with Schedule 125) adjusted for load and cost changes resulting from non-residential customers choosing service under Schedule 515 through 595 after the November update for the applicable year.

Net Variable Power Costs (NVPC) - The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Exclude power costs prudently incurred during RCEs.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the relevant period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- 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.

SCHEDULE 126 (Continued)

DEFINITIONS (Continued)

Reliability Contingency Event – An event qualifies as a Reliability Contingency Event (RCE) for cost recovery when 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 1.0357 to account for franchise fees, uncollectibles, and OPUC fees.

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.

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.

SCHEDULE 126 (Continued)

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	0.080 ¢ per kWh
15	0.080 ¢ per kWh
32	0.080 ¢ per kWh
38	0.080 ¢ per kWh
47	0.080 ¢ per kWh
49	0.080 ¢ per kWh
75	
Secondary	0.080 ¢ per kWh(1)
Primary	0.080 ¢ per kWh(1)
Subtransmission	0.080 ¢ per kWh(1)
83	0.080 ¢ per kWh
85	
Secondary	0.080 ¢ per kWh
Primary	0.080 ¢ per kWh
89	
Secondary	0.080 ¢ per kWh
Primary	0.080 ¢ per kWh
Subtransmission	0.080 ¢ per kWh
90	
Primary	0.080 ¢ per kWh
Subtransmission	0.080 ¢ per kWh
91	0.080 ¢ per kWh
92	0.080 ¢ per kWh
95	0.080 ¢ per kWh
485	
Secondary	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
489	
Secondary	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
Subtransmission	0.080 ¢ per kWh(2)
490	
Primary	0.080 ¢ per kWh
Subtransmission	0.080 ¢ per kWh

(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
491	0.080 ¢ per kWh
492	0.080 ¢ per kWh
495	0.080 ¢ per kWh
515	0.080 ¢ per kWh(2)
532	0.080 ¢ per kWh(2)
538	0.080 ¢ per kWh(2)
549	0.080 ¢ per kWh(2)
575	
Secondary	0.080 ¢ per kWh(1)
Primary	0.080 ¢ per kWh(1)
Subtransmission	0.080 ¢ per kWh(1)
583	0.080 ¢ per kWh(2)
585	0.080 ¢ per kWh(2)
Seconday	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
589	
Secondary	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
Subtransmission	0.080 ¢ per kWh(2)
590	
Primary	0.080 ¢ per kWh
Subtransmission	0.080 ¢ per kWh
591	0.080 ¢ per kWh(2)
592	0.080 ¢ per kWh(2)
595	0.080 ¢ per kWh(2)
689	
Secondary	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
Subtransmission	0.080 ¢ per kWh(2)

(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 2022, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2023:

Schedule		Annual Part A ¢ per kWh (1)	Annual Part B $ per KW of On-Peak Demand
32/532		(4.012)	
38/538		(4.731)	
75/575	Secondary	(4.286) (2)	
	Primary	(4.241) (2)	
	Subtransmission	(4.323) (2)	
83/583		(5.667)	4.68
85/585	Secondary	(5.830)	5.17
	Primary	(5.695)	5.15

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual Part A ¢ per kWh (1)	Annual Part B $ per KW of On-Peak Demand
89/589	Secondary	(4.286)	
	Primary	(4.241)	
	Subtransmission	(4.323)	
90/590	Primary	(4.531)	
	Subtransmission	(4.531)	
91/591		(3.059)	
95/595		(3.059)	
515		(2.686)	
549		(5.248)	
592		(4.346)	

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

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 (Continued)

LARGE NONRESIDENTIAL LOAD SHIFT TRUE-UP

For the November window, the Company will compute the Load Shift True-Up as the difference between the market prices used to establish the Schedule 128 Transition Adjustment and the average of the corresponding projected market prices during the first full week in December times the load leaving Cost of Service pricing. For the Balance of Year Transition Adjustment windows, the Company will compute the True-Up as the difference between the market prices used to establish the Schedule 128 Transition Adjustments and the corresponding projected market prices during the first full week after the close of the window times the amount of load leaving Cost of Service pricing. For the November election window, the Company will file for a deferral after the close of the window if the True-Up is greater than $240,000. The filing threshold for each of the quarterly windows will be $60,000.

BALANCING ACCOUNT

The Company will maintain a Balancing Account to accrue any deferred load shift true-up amounts. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts. These monies will be recovered from or refunded to all direct-access eligible Large Nonresidential Customers in a manner approved by the Commission.

CHANGES TO TRANSITION ADJUSTMENT RATES

The Short-Term Transition Adjustment is subject to modification to reflect any changes to the Energy Charge(s) of the Cost of Service Option that serve as the basis for the calculation of the Transition Adjustment. No change will be made, however, to the market price of power used to determine the applicable adjustment rate.

BALANCE-OF-YEAR TRANSITION ADJUSTMENT RATE

Eligible customers who have elected to receive service on a rate other than Cost of Service during a Balance-of-Year Election Window, will have the applicable Short-Term Balance-of-Year Transition Adjustment Rate applied to their bills.

The Balance-of-Year Transition Adjustment Rate will be filed, posted on the Company’s website and incorporated into this Schedule effective as follows:

- February 15th for an April 1st effective date

Where the date above is a weekend or state-recognized holiday, the filing date will be the next business day. The Short-Term Balance-of-Year Transition Adjustment will be posted by the Company on its website, https://portlandgeneral.com on the day the rate is filed with the Commission.

SCHEDULE 128 (Concluded)

Second Quarter – April 1st Balance of Year Adjustment Rate (1)

Schedule		Annual ¢ per kWh (2)
38/538		(0.328)
75/575	Secondary	(0.309) (3)
	Primary	(0.301) (3)
	Subtransmission	(0.280) (3)
83/583		0.171
85/585	Secondary	0.022
	Primary	0.023
89/589	Secondary	(0.309)
	Primary	(0.301)
	Subtransmission	(0.280)
90/590	Primary	(0.477)
	Subtransmission	(0.477)
91/591		0.331
95/595		0.331
592		(0.336)

(1) Applicable April 1, 2022 through December 31, 2022.
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected service under Schedules 485, 489, 490, 491, 492, and 495.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Periods A - P: 0.000 ¢ per kWh

The Schedule 129 Transition Cost Adjustment will be updated to reflect OPUC-approved changes in fixed generation costs during the five-year period.

For Enrollment Period Q (2018), 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
2019	2.972	2.958	2.625	2.576	2.493	2.540	2.511
2020	2.972	2.958	2.625	2.576	2.493	2.540	2.511
2021	2.972	2.958	2.625	2.576	2.493	2.540	2.511
2022	2.412	2.424	2.162	2.144	2.086	2.095	2.078
2023	2.412	2.424	2.162	2.144	2.086	2.095	2.078
After 2023	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 R (2019), 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
2020	2.376	2.359	2.042	2.004	1.918	1.960	1.968
2021	2.376	2.359	2.042	2.004	1.918	1.960	1.968
2022	1.816	1.825	1.579	1.572	1.511	1.515	1.535
2023	1.816	1.825	1.579	1.572	1.511	1.515	1.535
2024	2.066	2.070	1.818	1.807	1.744	1.720	1.686
After 2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000

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	2.725	2.723	2.455	2.432	2.480	2.349	2.270
2025	2.725	2.723	2.455	2.432	2.480	2.349	2.270
After 2025	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 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	1.101	1.094	0.829	0.837	0.839	0.769	0.820
2025	1.101	1.094	0.829	0.837	0.839	0.769	0.820
2026	1.101	1.094	0.829	0.837	0.839	0.769	0.820
After 2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000

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	(2.897)	(2.464)	(0.526)	(0.579)	(0.596)	(0.647)	(0.644)
2025	(2.897)	(2.464)	(0.526)	(0.579)	(0.596)	(0.647)	(0.644)
2026	(2.897)	(2.464)	(0.526)	(0.579)	(0.596)	(0.647)	(0.644)
2027	(2.897)	(2.464)	(0.526)	(0.579)	(0.596)	(0.647)	(0.644)
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 U (2022), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of On-Peak Demand	Sch. 485 Pri. Vol. $ per kW of On-Peak Demand	Sch. 489 Sec. Vol. $ per kW of On-Peak Demand	Sch. 489 Pri. Vol. $ per kW of On-Peal Demand	Sch. 489 Sub. Vol. $ per kW of On-Peak Demand	Sch. 490 Pri. Vol. $ per kW of On-Peak Demand	Schs. 491/492/495 $ per kW of On-Peak Demand
2023	5.17	5.15	0.000	0.000	0.000	0.000	0.000
2024	9.56	9.45	0.000	0.000	0.000	0.000	0.000
2025	9.56	9.45	0.000	0.000	0.000	0.000	0.000
2026	9.56	9.45	0.000	0.000	0.000	0.000	0.000
2027	9.56	9.45	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

<u>Three Year Opt-Out</u>

This option was not available during Enrollment Periods A and B

For Enrollment Periods C – R: No Longer Available

For Enrollment Period S (2020), the Transition Cost Adjustment will be:

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	3.170	3.085	2.770	2.718	2.624	2.476	2.612
2022	3.170	3.085	2.770	2.718	2.624	2.476	2.612
2023	3.170	3.085	2.770	2.718	2.624	2.476	2.612

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out (Continued)

For Enrollment Period T (2021), the Transition Cost Adjustment will be:

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	1.376	1.312	1.002	0.983	1.046	0.770	1.125
2023	1.376	1.312	1.002	0.983	1.046	0.770	1.125
2024	1.376	1.312	1.002	0.983	1.046	0.770	1.125

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	(3.779)	(3.703)	(2.249)	(2.226)	(2.292)	(2.567)	(1.954)
2024	(2.172)	(2.142)	(0.655)	(0.649)	(0.586)	(1.021)	(0.645)
2025	(1.266)	(1.294)	0.246	0.242	0.425	(0.170)	(0.140)

For Enrollment Period U (2022), the Generation Demand Charge 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	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

SCHEDULE 129 (Continued)

SPECIAL CONDITIONS

1. Annually, the total amount paid in Schedule 129 Long-Term Transition Cost Adjustments associated with Enrollment Periods A through K will be collected through applicable Large Nonresidential rate schedules (Schedules 75, 85, 89, 90, 485, 489, 490, 575, 585, 589 and 590), through either the System Usage or Distribution Charges. Commencing with Enrollment Period L, the Schedule 129 amounts paid or received will be collected from all rate schedules, through either System Usage Charges or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedules 485, 489, 490, 491, 492, and 495 customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges or Distribution Charges of all rate schedules. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage or Distribution Charges resulting from changes in fixed generation revenues shall not result in an overall rate increase or decrease of more than 2 percent except as noted below. For those Enrollment Periods in which the first-year Schedule 129 Transition Adjustments are expected to be positive charges to participants, the projected first-year revenues from Schedule 129 will be netted against the changes in fixed generation costs for purposes of calculating the proposed overall rate increase or decrease. Should the rate increase or decrease exceed 2 percent, the amounts exceeding 2 percent will be deferred for future recovery through a balancing account. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined.

3. In determining changes in fixed generation revenues from movement to or from Schedules 485, 489, 490, 491, 492, and 495, the following factors will be used:

Schedule		¢ per kWh
85	Secondary	2.715
	Primary	2.687
89	Secondary	2.583
	Primary	2.555
	Subtransmission	4.528
90	Primary	2.547
	Subtransmission	2.547
91		2.423
92		2.423
95		2.423

SCHEDULE 129 (Concluded)

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 485, 489, 490, 491, 492 or 495.

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.

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 134
GRESHAM RETROACTIVE PRIVILEGE TAX PAYMENT ADJUSTMENT

PURPOSE

To recover from Customers in the City of Gresham the privilege taxes and court-ordered, associated interest amounts assessed retroactively by the City of Gresham following an Oregon Supreme Court decision in 2016.

APPLICABLE

All Customers receiving Electricity Service within the City of Gresham.

BALANCING ACCOUNT

The Company will establish a Balancing Account to record the difference between amounts collected under this schedule, net of uncollectible accounts and amounts authorized to be recovered. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts. The disposition of any over- or under-recovery amount will be subject to Commission approval.

GRESHAM PRIVILEGE TAX SETTLEMENT RECOVERY RATE

The Rate is:

> 0.0% of the total billed amount to the Customer excluding the Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes. Certain Large Nonresidential Customers with existing limitations on privilege tax obligations will be billed in accordance with these existing limitations.

SCHEDULE 135
DEMAND RESPONSE COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with demand response pilots not otherwise included in rates. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R and 689.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.094	¢ per kWh
15/515	0.073	¢ per kWh
32/532	0.081	¢ per kWh
38/538	0.074	¢ per kWh
47	0.090	¢ per kWh
49/549	0.092	¢ per kWh
75/575		
Secondary	0.075	¢ per kWh[(1)]
Primary	0.074	¢ per kWh[(1)]
Subtransmission	0.076	¢ per kWh[(1)]
83/583	0.080	¢ per kWh
85/585		
Secondary	0.077	¢ per kWh
Primary	0.074	¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 135 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89/589		
Secondary	0.075	¢ per kWh
Primary	0.074	¢ per kWh
Subtransmission	0.076	¢ per kWh
90/590		
Primary	0.070	¢ per kWh
Subtransmission	0.070	¢ per kWh
91/591	0.068	¢ per kWh
92/592	0.072	¢ per kWh
95/595	0.068	¢ per kWh

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with automated demand response and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule’s forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

SCHEDULE 136
OREGON COMMUNITY SOLAR PROGRAM
COST RECOVERY MECHANISM

PURPOSE

The purpose of this Schedule is to recover costs incurred during and for the development (or modification) of the Oregon Community Solar Program (Oregon CSP) including the costs associated with the State of Oregon's Program Administrator, Low Income Facilitator, the company's prudently incurred costs associated with implementing the Community Solar Program that are not otherwise included in rates, and payments to participants in the Oregon CSP. Company incurred costs to implement the state program do not include costs associated with the company developing a community solar project. This cost recovery mechanism is authorized by ORS 757.386 (7)(c) and OAR 860-088-0160. The Oregon CSP is an optional program that will provide PGE customers the opportunity to voluntarily subscribe to the generation output of eligible community solar projects. This adjustment schedule is implemented as an automatic adjustment clause as provided under ORS 757.210 to allow recovery of operations and maintenance start-up costs as soon as the cost data is approved by the Commission.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R and 576R.

ADUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.021	¢ per kWh
15/515	0.017	¢ per kWh
32/532	0.019	¢ per kWh
38/538	0.021	¢ per kWh
47	0.032	¢ per kWh
49/549	0.025	¢ per kWh
75/575		
Secondary	0.020	¢ per kWh
Primary	0.010	¢ per kWh
Subtransmission	0.010	¢ per kWh

SCHEDULE 136 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
83/583	0.015	¢ per kWh
85/485/585		
Secondary	0.013	¢ per kWh
Primary	0.011	¢ per kWh
89/489/589/689		
Secondary	0.020	¢ per kWh
Primary	0.010	¢ per kWh
Subtransmission	0.010	¢ per kWh
90/490/590		
Primary	0.010	¢ per kWh
Subtransmission	0.010	¢ per kWh
91/491/591	0.017	¢ per kWh
92/492/592	0.011	¢ per kWh
95/495/595	0.017	¢ per kWh

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between incremental costs associated with the Oregon CSP and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

SPECIAL CONDITIONS

1. Pursuant to OAR 860-088-0160 (1), Oregon CSP start-up costs are:

   - Costs associated with the Program Administrator and Low-Income Facilitator; and
   - Each utility's prudently incurred start-up costs associated with implementing the Community Solar Program. These costs include, but are not limited to, costs associated with customer account information transfer and on-bill crediting and payment, but exclude any costs associated with the electric utility developing a project.

SCHEDULE 136 (Concluded)

SPECIAL CONDITIONS (Continued)

2. PGE will remit payments to the Program Administrator on a monthly basis for program costs including performing work as provided in OAR 860-088-0020 and OAR 860-088-0030 within 15 days receipt of the Commission's approval of eligible costs.

3. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule.

SCHEDULE 137
CUSTOMER-OWNED SOLAR PAYMENT OPTION
COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the costs associated with the Solar Payment Option pilot not otherwise included in rates. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210, and defined in Renewable Portfolio Standards.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R and 576R.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate	
7	0.005	¢ per kWh
15/515	0.003	¢ per kWh
32/532	0.004	¢ per kWh
38/538	0.005	¢ per kWh
47	0.007	¢ per kWh
49/549	0.005	¢ per kWh
75/575		
Secondary	0.002	¢ per kWh(1)
Primary	0.002	¢ per kWh(1)
Subtransmission	0.003	¢ per kWh(1)
83/585	0.003	¢ per kWh
85/585		
Secondary	0.003	¢ per kWh
Primary	0.003	¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 137 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate	
89/589		
Secondary	0.002	¢ per kWh
Primary	0.002	¢ per kWh
Subtransmission	0.003	¢ per kWh
90/590		
Primary	0.002	¢ per kWh
Subtransmission	0.002	¢ per kWh
91/591	0.003	¢ per kWh
92/592	0.003	¢ per kWh
95/595	0.003	¢ per kWh
485		
Secondary	0.003	¢ per kWh
Primary	0.003	¢ per kWh
489/689		
Secondary	0.002	¢ per kWh
Primary	0.002	¢ per kWh
Subtransmission	0.003	¢ per kWh
490		
Primary	0.002	¢ per kWh
Subtransmission	0.002	¢ per kWh
491	0.003	¢ per kWh
492	0.003	¢ per kWh
495	0.003	¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with the Solar Payment Option pilot and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule.

SCHEDULE 138
ENERGY STORAGE COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with HB 2193 energy storage pilots not otherwise included in rates. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495 and 576R and 689.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate
7	0.012 ¢ per kWh
15/515	0.009 ¢ per kWh
32/532	0.011 ¢ per kWh
38/538	0.010 ¢ per kWh
47	0.012 ¢ per kWh
49/549	0.012 ¢ per kWh
75/575	
Secondary	0.010 ¢ per kWh
Primary	0.010 ¢ per kWh
Subtransmission	0.010 ¢ per kWh
83/583	0.010 ¢ per kWh
85/585	
Secondary	0.010 ¢ per kWh
Primary	0.010 ¢ per kWh

SCHEDULE 138 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
89/589	
Secondary	0.010 ¢ per kWh
Primary	0.010 ¢ per kWh
Subtransmission	0.010 ¢ per kWh
90/590	
Primary	0.009 ¢ per kWh
Subtransmission	0.009 ¢ per kWh
91/591	0.009 ¢ per kWh
92/592	0.009 ¢ per kWh
95/595	0.009 ¢ per kWh

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with energy storage pilots and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

SCHEDULE 139
NEW LARGE LOAD TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected New Large Load Cost-of-Service Opt-Out service under Schedule 689. This transition adjustment will be paid when the Customer begins service under Schedule 689. This transition adjustment represents 20 percent of the Company's fixed generation costs and is subject to change annually during the Customer's five-years enrolled in Schedule 689. At the end of the Customer's five-year payment term of these transition adjustments, the Customer will no longer be subject to the charges in this rate schedule. The Customer will not be subject to the charges in this rate schedule with at least three years of notification to the Company of a return to cost-of-service pricing.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Period 1 (2020), the Transition Cost Adjustment will be:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh
2020	0.679	0.667	0.658
2021	0.702	0.689	0.680
2022	0.587	0.580	0.576
2023	0.655	0.648	0.645
2024	0.635	0.627	0.623
2025*	0.635	0.627	0.623
After 2026	0.000	0.000	0.000

For Period 2 (2021), the Transition Cost Adjustment will be:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh
2021	0.702	0.689	0.680
2022	0.587	0.580	0.576
2023	0.655	0.648	0.645
2024	0.635	0.627	0.623
2025	0.635	0.627	0.623
2026*	0.635	0.627	0.623
After 2027	0.000	0.000	0.000

*Applicable pricing only to completion of five-year period and zero thereafter.

SCHEDULE 139 (Continued)

TRANSITION COST ADJUSTMENT (Continued)

For Period 3 (2022), the Transition Cost Adjustment will be:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh
2022	0.587	0.580	0.576
2023	0.655	0.648	0.645
2024	0.635	0.627	0.623
2025	0.635	0.627	0.623
2026	0.635	0.627	0.623
2027*	0.635	0.627	0.623
After 2028	0.000	0.000	0.000

For Period 4 (2023), the Transition Cost Adjustment will be:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh
2023	0.655	0.648	0.645
2024	0.635	0.627	0.623
2025	0.635	0.627	0.623
2026	0.635	0.627	0.623
2027	0.635	0.627	0.623
2028*	0.635	0.627	0.623
After 2029	0.000	0.000	0.000

*Applicable pricing only to completion of five-year period and zero thereafter.

SPECIAL CONDITIONS

1. Annually, the total amount collected in Schedule 139 New Large Load Transition Cost Adjustments will be incorporated into all rate schedules, through either System Usage Charges or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

SCHEDULE 139 (Concluded)

SPECIAL CONDITIONS (Continued)

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedules 689 Customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges or Distribution Charges of all rate schedules. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage or Distribution Charges resulting from changes in fixed generation revenues shall not result in an overall rate increase or decrease of more than 2 percent except as noted below. For those Enrollment Periods in which the first-year Schedule 139 Transition Adjustments are expected to be positive charges to participants, the projected first-year revenues from Schedule 139 will be netted against the changes in fixed generation costs for purposes of calculating the proposed overall rate increase or decrease. Should the rate increase or decrease exceed 2 percent, the amounts exceeding 2 percent will be deferred for future recovery through a balancing account. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined.

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 689 but will not exceed 60 months.

SCHEDULE 142
UNDERGROUND CONVERSION COST RECOVERY ADJUSTMENT

PURPOSE

To recover costs incurred by the Company to convert electric facilities from overhead to underground from customers within the boundaries of the local government requiring such conversion at the Company's expense, as required by OAR 860-022-0046.

APPLICABLE

To all bills for electric service supplied by the Company within the boundaries of the local government requiring the conversion of electric facilities from overhead to underground at the Company's expense.

ADJUSTMENT RATE

The Adjustment Rate is the applicable percentage as listed below of the total bill amount to each Customer located within the applicable local government's boundaries excluding the Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes.

Municipality	Ordinance Number	Effective Date	Projected Term	Adjustment Rate

SPECIAL CONDITIONS

1. For each local government underground conversion project, the Company will establish a tracking mechanism that will track the receipts from each listed Adjustment Rate.

2. In accordance with OAR 860-022-0046, the Company will accrue interest for the unamortized conversion costs at the effective rate of the senior security issue that most recently preceded the incurrence of the conversion cost for the local government.

3. The Company will terminate the collection of the Adjustment Rate at the time when the conversion costs associated with each local government underground conversion project listed above are fully recovered.

4. The Adjustment Rate will be separately stated on the Customer bills rendered within the boundaries of the applicable local government.

SCHEDULE 143
SPENT FUEL ADJUSTMENT

PURPOSE

The purpose of this schedule is to implement in rates the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund and any ongoing refunds from the United States Department of Energy. Also included are pollution control tax credits associated with the Independent Spent Fuel Storage Installation at the Trojan nuclear plant.

APPLICABLE

To all bills for Electricity Service calculated under all schedules and contracts, except those Customers explicitly exempted.

PART A – TROJAN NUCLEAR DECOMMISSIONING TRUST FUND

Part A consists of the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund and any ongoing refunds from the United States Department of Energy.

PART B – ISFSI ADJUSTMENT

Part B consists of the amortization of the payments from the Oregon Department of Energy related to state pollution control tax credits for the Independent Spent Fuel Storage Installation at Trojan.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Part A	Part B	Adjustment Rate	
7	(0.019)	0.000	(0.019)	¢ per kWh
15/515	(0.014)	0.000	(0.014)	¢ per kWh
32/532	(0.016)	0.000	(0.016)	¢ per kWh
38/538	(0.015)	0.000	(0.015)	¢ per kWh
47	(0.018)	0.000	(0.018)	¢ per kWh
49/549	(0.018)	0.000	(0.018)	¢ per kWh
75/575				
Secondary	(0.015)	0.000	(0.015)	¢ per kWh(1)
Primary	(0.015)	0.000	(0.015)	¢ per kWh(1)
Subtransmission	(0.015)	0.000	(0.015)	¢ per kWh(1)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 143 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
83/583	(0.016)	0.000	(0.016)	¢ per kWh
85/585				
Secondary	(0.016)	0.000	(0.016)	¢ per kWh
Primary	(0.015)	0.000	(0.015)	¢ per kWh
89/589				
Secondary	(0.015)	0.000	(0.015)	¢ per kWh
Primary	(0.015)	0.000	(0.015)	¢ per kWh
Subtransmission	(0.015)	0.000	(0.015)	¢ per kWh
90/590				
Primary	(0.014)	0.000	(0.014)	¢ per kWh
Subtransmission	(0.014)	0.000	(0.014)	¢ per kWh
91/591	(0.014)	0.000	(0.014)	¢ per kWh
92/592	(0.014)	0.000	(0.014)	¢ per kWh
95/595	(0.014)	0.000	(0.014)	¢ per kWh
485				
Secondary	(0.011)	0.000	(0.011)	¢ per kWh
Primary	(0.011)	0.000	(0.011)	¢ per kWh
489/689				
Secondary	(0.015)	0.000	(0.015)	¢ per kWh
Primary	(0.015)	0.000	(0.015)	¢ per kWh
Subtransmission	(0.015)	0.000	(0.015)	¢ per kWh
490				
Primary	(0.014)	0.000	(0.014)	¢ per kWh
Subtransmission	(0.014)	0.000	(0.014)	¢ per kWh
491	(0.014)	0.000	(0.014)	¢ per kWh
492	(0.014)	0.000	(0.014)	¢ per kWh
495	(0.014)	0.000	(0.014)	¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the difference between the Trojan Nuclear Decommissioning Trust Fund refund, ongoing refunds, and the ISFSI payments and the actual Schedule 143 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts.

SCHEDULE 145
BOARDMAN POWER PLANT
DECOMMISSIONING ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the revenue requirement effect of the decommissioning expenses related to the Boardman power plant. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R and 689.

ADJUSTMENT RATES

Schedule 145 Adjustment Rates will be set based an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
15/515	0.000 ¢ per kWh
32/532	0.000 ¢ per kWh
38/538	0.000 ¢ per kWh
47	0.000 ¢ per kWh
49/549	0.000 ¢ per kWh
75/575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
83/583	0.000 ¢ per kWh
85/585	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh

SCHEDULE 145 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
89/589	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
90/590	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
91/591	0.000 ¢ per kWh
92/592	0.000 ¢ per kWh
95/595	0.000 ¢ per kWh

DETERMINATION OF ADJUSTMENT AMOUNT

The Adjustment Amount is the revenue requirements related to decommissioning of the Boardman Power Plant using a plant end of life assumption of year-end 2020. The decommissioning revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates. Only changes to decommissioning expense are included in the revenue requirements.

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Boardman Power Plant decommissioning revenue requirement.

BALANCING ACCOUNT

The Company will maintain a balancing account to track the difference between the Schedule 145 Decommissioning Revenue Requirements and the actual Schedule 145 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts.

TIME AND MANNER OF FILING

Commencing in 2011, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the following year based on the updated revenue requirements described above.

2. Work papers supporting the Schedule 145 prices, the updated decommissioning revenue requirements, the projected applicable billing determinants, and the projected balancing account activity.

SCHEDULE 146
COLSTRIP POWER PLANT
OPERATING LIFE ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the Company's share of the full revenue requirement for the Colstrip Power Plant Units 3 and 4 and associated common facilities. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R and 689.

ADJUSTMENT RATES

Schedule 146 Adjustment Rates will be set based on an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate
7	0.416 ¢ per kWh
15/515	0.296 ¢ per kWh
32/532	0.356 ¢ per kWh
38/538	0.326 ¢ per kWh
47	0.396 ¢ per kWh
49/549	0.408 ¢ per kWh
75/575	
Secondary	0.331 ¢ per kWh
Primary	0.326 ¢ per kWh
Subtransmission	0.332 ¢ per kWh
83/583	0.352 ¢ per kWh
85/585	
Secondary	0.340 ¢ per kWh
Primary	0.333 ¢ per kWh
89/589	
Secondary	0.331 ¢ per kWh
Primary	0.326 ¢ per kWh
Subtransmission	0.332 ¢ per kWh
90/590	
Primary	0.304 ¢ per kWh
Subtransmission	0.304 ¢ per kWh
91/591	0.300 ¢ per kWh
92/592	0.318 ¢ per kWh
95/595	0.300 ¢ per kWh

SCHEDULE 146 (Continued)

PART A- DECOMMISSIONING AMOUNTS
Part A consists of the revenue requirements related to decommissioning of the Colstrip Power Plant Units 3 and 4. The decommissioning revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates.

PART B- DEPRECIATION AMOUNTS

Part B consists of the revenue requirements related to depreciation of the Colstrip Power Plant Units 3 and 4. The depreciation revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates.

PART C- REMAINING AMOUNTS

Part C consists of the full revenue requirement associated with the Colstrip Power Plant Units 3 and 4 and associated common facilities (including all identifiable capital- and expense-related costs and other revenues), excluding associated transmission facilities, costs allowable for recovery through PGE's existing Schedule 125 (Annual Power Cost Update), and amounts identified in Parts A and B above. The revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return, and return on equity rates.

DETERMINATION OF ADJUSTMENT AMOUNTS

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 revenue requirement (Parts A, B and C).

BALANCING ACCOUNT

The Company will maintain a balancing account to track the difference between the Schedule 146 Part A only amounts and the actual Schedule 146 revenues for Part A. This difference will accrue interest at the Commission-authorized rate for deferred accounts. No other amounts included within Schedule 146 will be subject to balancing account treatment.

SCHEDULE 146 (Concluded)

TIME AND MANNER OF FILING

Commencing in 2022, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the following year based on the updated revenue requirements described above.

2. Work papers supporting the Schedule 146 prices, the updated depreciation and decommissioning revenue requirements, the projected applicable billing determinants, and the projected balancing account activity.

With respect to a Schedule 146 rate change for the inclusion or update of costs outside of revised decommissioning or operating life adjustments and in compliance with the Commission's findings in separate cost recovery proceeding(s), the Company will file updated Schedule 146 rates by no less than 30 days prior to the rate effective date.

SCHEDULE 149
ENVIRONMENTAL REMEDIATION COST RECOVERY ADJUSTMENT
AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the costs and revenues associated with the Portland Harbor Superfund site ("Portland Harbor"), the Natural Resource Damage obligation, the Downtown Reach portions of the Willamette River, and the Harborton Restoration Project. This adjustment schedule is implemented as an automatic adjustment clause as provided under ORS 757.210.

AVAILABLE

In all territory served by Portland General Electric Company ("PGE").

APPLICABLE

To all Schedules.

ANNUAL ACCOUNT & BALANCING ACCOUNT

By Order No. 17-071, the Commission approved a deferral of environmental-related costs and revenues, effective July 15, 2016, that flow into the Portland Harbor Environmental Remediation Account ("PHERA"). The PHERA Annual Account records Environmental Remediation Costs ("ERC"), the costs of developing the Harborton Restoration Project, and Environmental Remediation Revenues ("ERR"). The balance in the Annual Account that has not been reviewed by the Commission for prudence shall accrue interest at the authorized rate of return approved in PGE's most recent general rate case. Costs and revenues in the Annual Account that have been reviewed for prudency and remain following the earnings test will be transferred to the PHERA Balancing Account and will accrue interest at the average of the five-year U.S. Treasury rate plus 100 basis points (the "PURE Rate").

EARNINGS TEST

Subject to the conditions stated below, the recovery from customers of certain ERC is subject to an earnings review and test for the year that the costs were paid. Following a prudence review, PGE will be allowed to place prudent expenses and proceeds into the Balancing Account to the extent that PGE's Actual Regulated Return on Equity ("ROE") does not exceed its ROE authorized by the Commission in PGE's most recent general rate case. A fixed $6.0 million each year in ERC and Harborton Restoration Project development costs, currently estimated at $10-$12 million, are not subject to the earnings test. Proceeds from insurance companies and DSAY ("Discount Service Acre Year") sales will not be subject to an earnings review, but will be subject to a prudency review.

SCHEDULE 149 (Continued)

DEFINITIONS

Annual Allocated Revenue ("AAR") - The Annual Allocated Revenue is the sum of annual revenue from this Tariff plus DSAY revenues (net of prudent Harborton Restoration Project development costs), insurance proceeds, $3.56 million currently in base rates (subject to revision by the Commission), AAR balances carried forward, and accumulated interest. The $3.56 million per year currently in base rates will be credited to the PHERA Annual Account on a monthly basis, in the amount of $0.2967 million, until PGE's next general rate case when the appropriate amount to be included in rates, if any, will be re-examined. For the month of July 2016, a prorated amount of $0.1627 million shall be credited to the PHERA Annual Account. The amount of insurance proceeds and net DSAY revenues to be included in the AAR is calculated as total proceeds divided by the expected remaining life of the projects, inclusive of the year in which they are received (so that such proceeds are equally allocated). The initial assumption is that the remaining life is through 2028, and may be revised by the Commission (on a going-forward basis) in any subsequent Commission review process.

Downtown Reach - The segment of the Willamette River between River Miles 12 and 16 is known as the "Downtown Reach."

DSAY - Discount Service Acre Year ("DSAY") obligations or credits measure damage or mitigation to natural resources.

Environmental Remediation Costs ("ERC") - Environmental Remediation Costs are costs related to remediation of the Portland Harbor and Downtown Reach sites that include, but are not limited to, the design, permitting, construction, on-going monitoring, and trustee financial requirements necessary for habitat restoration development, investigation, testing, sampling, monitoring, removal, disposal, storage, remediation, or other treatment of residues, litigation costs/expenses or other liabilities, disposal sites, sites that otherwise contain contamination that requires remediation for which PGE is responsible, or sites to which material may have migrated; the Natural Resource Damage obligation; Harborton Restoration Project O&M and endowment costs; and costs related to pursuing insurance recoveries. ERC do not include Harborton Restoration Project development costs, which include, but are not limited to, costs incurred as of the date of the UM 1789 Stipulation, development and construction costs, permitting costs, costs paid to the Trustees for participation in the NRD restoration project, and future termination-related costs if applicable. Further, the remediation sites eligible for inclusion as ERCs are limited to those sites identified in Appendix A to the UM 1789 Stipulation.

Environmental Remediation Revenues - Environmental Remediation Revenues include: (1) DSAY revenues net of prudent Harborton Restoration Project development costs; (2) insurance proceeds; (3) the amount included in base rates for environmental remediation activities at Portland Harbor or Downtown Reach; (4) the Schedule 149 tariff revenue; and (5) interest.

Harborton Restoration Project - PGE intends to design, construct, monitor and maintain the Harborton Restoration Project at 12500 NW Marina Way, Portland, Multnomah County, Oregon. PGE will restore and enhance approximately 62 acres of the 78.51 acres of the overall property.

SCHEDULE 149 (Continued)

DEFINITIONS (Continued)

Natural Resource Damage - The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 ("CERCLA" or "Superfund") and Oil Pollution Act ("OPA") Programs require the cleanup for contaminants that are released and pose a threat to human health and the environment. In addition to the requirements for cleanup under these cleanup programs, the Superfund and OPA cleanup programs also require that natural resources be restored to the state that they were at before injury from environmental contaminants. If natural resources are not restored, then Trustees will seek compensation for the injury, quantified as Natural Resource Damages ("NRD") from parties responsible for the release of the contaminants. NRD in this tariff refers to NRD obligations assessed against PGE.

Portland Harbor Superfund - The Superfund designation is pursuant to CERCLA. 42 U.S.C Section 9601 et seq. The CERCLA and OPA programs require the cleanup for contaminants that are released and pose a threat to human health and the environment.

PURE - The Prudence-Reviewed Unamortized Environmental Remediation Expense ("PURE") rate that is established early each year by Staff and represents the average of the 5-year US Treasury rate plus 100 basis points.

SCHEDULE 149 (Continued)

ADJUSTMENT RATES

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
15/515	0.000 ¢ per kWh
32/532	0.000 ¢ per kWh
38/538	0.000 ¢ per kWh
47	0.000 ¢ per kWh
49/549	0.000 ¢ per kWh
75/575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
76R/576R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
83/583	0.000 ¢ per kWh
85/485/585	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
89/489/589/689	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
90/490/590	
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
91/491/591	0.000 ¢ per kWh
92/492/592	0.000 ¢ per kWh
95/495/595	0.000 ¢ per kWh

SPECIAL CONDITIONS

1. By March 15 of each year, PGE will submit a prudence review filing that includes a report of all activity associated with Harborton Restoration Project development costs, ERC, ERR, and other related third-party proceeds recorded in the PHERA Annual Account. Staff and other Parties will complete the prudence review, and Staff will submit its report and recommendation to the Commission within 120 days of submittal. Only cash expenditures will be included in the PHERA Annual Account for recovery under the PHERA mechanism. PGE shall defer, separately track, and capitalize as a regulatory asset, contingent environmental liability accruals. This regulatory asset shall not be included in rate base and PGE shall not earn a return on the balance.

SCHEDULE 149 (Continued)

SPECIAL CONDITIONS (Continued)

2. The amount of costs and revenues that is transferred to the Balancing Account is determined on an annual basis and subject to an earnings test. The amount transferred is calculated as the current year's ERC and any remaining Harborton Restoration Project development costs not offset by that year's DSAY revenues, less the AAR. Harborton Restoration Project development costs incurred prior to the first year with DSAY revenues may be netted against those revenues.

3. The earnings test in this schedule will be applied after the Power Cost Adjustment Mechanism ("PCAM") earnings test. The amount subject to the earnings test is prudently incurred ERC that exceed $6.0 million. In addition, Harborton Restoration Project development costs are not subject to an earnings test.

4. The amount of annual ERC recoverable post-application of the earnings test is reduced by the AAR and then the remaining balance, if any, is transferred to the Balancing Account for recovery across the following five years.

5. If ERC in any year are less than the AAR, then the remaining ARR balance will be used to offset accumulated costs in the Balancing Account that were allocated to that year. Any remaining positive balances (more AAR revenues than current and accumulated costs) will roll forward as an addition to the next year's AAR.

6. Functionalized costs recoverable through Schedule 149 will be allocated to each rate schedule according to relative use of generation, distribution, and transmission service. Long-Term Direct Access customers will be priced at Cost-of-Service for purposes of allocating costs.

7. In the event that the amount in the PHERA Balancing Account results in a potential refund to customers, subject to approval by the Commission, PGE will determine if the refund should be applied to Customer bills, or if the credit balance should carry to a future period. A credit balance may be carried to a future period if it is determined by the Commission that the credit balance is best used to offset future expected ERC not yet recorded in the deferral account, or for such other reasons as the Commission may determine.

8. Adjustments under this Schedule shall continue for a period of five years following the date that the last remediation expenses are incurred and paid, or such other date that the Commission may decide.

9. Development costs associated with the creation of DSAYs from the Harborton Restoration Project shall be deferred as regulatory assets.

SCHEDULE 149 (Concluded)

SPECIAL CONDITIONS (Continued)

10. PGE shall defer and capitalize, as a regulatory asset, incurred costs associated with environmental liabilities accrued according to Accounting Standards Codification ("ASC") 410, *Environmental Obligations* and pursuant to Generally Accepted Accounting Principles ("GAAP"). Any GAAP accounting accruals recorded would not be subject to interest computation or earnings test as no cash amounts have been paid or received.

11. The PHERA is subject to review no less frequently than every two years, when significant new information becomes available, or during a general rate case. All aspects of the mechanism are subject to review and revision, including but not limited to, the earnings test, the exempt ERC amount, and incentives for cost management such as sharing.

12. If Harborton Restoration Project development costs, currently estimated at $10-$12 million, exceed DSAY revenues, PGE will not recover development costs from customers in excess of DSAY revenues retained by PGE. Harborton Restoration Project development costs include all costs associated with the Harborton Restoration Project development, including but not limited to, costs incurred as of the date of the UM 1789 Stipulation, development and construction costs, permitting costs, costs paid to the Trustees for participation in the NRD restoration project, and future termination-related costs if applicable.

SCHEDULE 150
TRANSPORTATION ELECTRIFICATION COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the costs to support the statewide decarbonization goals and long-term load growth through transportation electrification not otherwise included in rates. Expenditure of the revenue collected under this schedule will be made pursuant to ORS 757.357. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, and 576R.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule		Adjustment Rate	
7		0.074	¢ per kWh
15/515		0.058	¢ per kWh
32/532		0.070	¢ per kWh
38/538		0.089	¢ per kWh
47		0.141	¢ per kWh
49/549		0.112	¢ per kWh
75/575			
	Secondary	0.038	¢ per kWh
	Primary	0.019	¢ per kWh
	Subtransmission	0.014	¢ per kWh
83/583		0.029	¢ per kWh
85/585			
	Secondary	0.025	¢ per kWh
	Primary	0.021	¢ per kWh
89/589			
	Secondary	0.038	¢ per kWh
	Primary	0.019	¢ per kWh
	Subtransmission	0.014	¢ per kWh

SCHEDULE 150 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
90/490/590		
Primary	0.018	¢ per kWh
Subtransmission	0.018	¢ per kWh
91/491/591	0.068	¢ per kWh
92/492/592	0.030	¢ per kWh
95/495/595	0.068	¢ per kWh
485		
Secondary	0.025	¢ per kWh
Primary	0.021	¢ per kWh
489		
Secondary	0.038	¢ per kWh
Primary	0.019	¢ per kWh
Subtransmission	0.014	¢ per kWh
689		
Secondary	0.038	¢ per kWh
Primary	0.019	¢ per kWh
Subtransmission	0.014	¢ per kWh

Part A collects a charge to support transportation electrification in accordance with Section 2(2) of House Bill 2165.

Part B recovers costs associated with transportation electrification pilots not otherwise included in rates.

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with transportation electrification and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

SCHEDULE 150 (Concluded)

SPECIAL CONDITIONS

1. For part A, the adjustment rate of the transportation electrification charges will be updated every year. The forecasted total retail revenue will be based on the rates in effect on January 1 of each year.

2. For part B, the costs associated with Docket No. UM 1938 and UM 2003 will be created for each schedule using applicable schedule's forecasted energy on the basis of an equal percent of distribution revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule.

3. For part B, any future costs associated with transportation electriciation pilots will be created for each schedule using applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule.

SCHEDULE 152
MAJOR EVENT COST RECOVERY

PURPOSE

The purpose of this schedule is to recover costs incurred relating to the 2020 and 2021 wildfire and 2021 ice storm emergencies.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, and 576R.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.146	¢ per kWh
15/515	0.123	¢ per kWh
32/532	0.142	¢ per kWh
38/538	0.174	¢ per kWh
47	0.309	¢ per kWh
49/549	0.206	¢ per kWh
75/575		
Secondary	0.020	¢ per kWh
Primary	0.020	¢ per kWh
Subtransmission	0.020	¢ per kWh
83/583	0.082	¢ per kWh
85/485/585		
Secondary	0.051	¢ per kWh
Primary	0.037	¢ per kWh

SCHEDULE 152 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate	
89/489/589/689		
Secondary	0.020	¢ per kWh
Primary	0.020	¢ per kWh
Subtransmission	0.020	¢ per kWh
90/490/590		
Primary	0.018	¢ per kWh
Subtransmission	0.018	¢ per kWh
91/491/591	0.123	¢ per kWh
92/492/592	0.038	¢ per kWh
95/495/595	0.123	¢ per kWh

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the difference between deferred amounts and the actual Schedule 152 revenues.

SCHEDULE 200
DISPATCHABLE STANDBY GENERATION

PURPOSE

To provide the Company with additional generation capacity by contracting with Large Nonresidential Customers for the right to operate their Generation Resource(s) for the purpose of providing Grid Services and averting situations that could lead to power quality problems for the power supply in the local region.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers with 250 kW or greater of permanently installed Generation Resource(s) in place or planned for installation within 24 months.

DEFINITIONS

Aid in Construction Allowance - The amount of funding PGE may contribute to an individual project to enable the Generation Resource to be integrated with PGE for dispatch to support Grid Services.

Ancillary Services - Includes Contingency Reserve and Frequency Response for the purposes of this program.

Battery Energy Storage System (BESS) - An electrochemical device that charges (or collects energy) from the grid or on-site power generation sources and then discharges that energy at a later time to provide electricity or other grid services when needed.

Contingency Reserve - The ability to dispatch an enrolled Generation Resource in response to a critical need for replacement power in the region.

Demand Response - The dispatch of a qualified enrolled Generation Resource for the purpose of strategically reducing energy usage during times of peak demand and/or high energy market pricing.

Dispatchable Standby Generation Agreement (Agreement) - An agreement between the Company and Customer that defines the length of the Agreement, amount of capacity nominated to PGE, number of hours PGE may dispatch the Generation Resource, the terms of the Customer's usage of the Generation Resource, and amount of the Aid in Construction Allowance.

Frequency Response - An immediate reduction of site load or dispatch of power at a predetermined level for a short duration in response to a disruption that causes the frequency of the electrical system to fall below a nominal 60 hertz (Hz).

SCHEDULE 200 (Continued)

DEFINITIONS (Continued)

Generation Resource - An Internal Combustion Generator or a Battery Energy Storage System integrated with PGE pursuant to this Schedule.

Grid Services - For the purposes of this Schedule includes the dispatch of Generation Resources for Ancillary Services or Demand Response.

Internal Combustion Generator - A mechanical engine used to generate electricity.

Reserve Status - Indicates a resource is available for dispatch by PGE.

CUSTOMER RESPONSIBILITIES

The Customer will grant the Company access to its Generation Resource(s) such that the Company can operate the Generation Resource(s) at the site or remotely operate the Generation Resource(s) in parallel with the Company's distribution system.

The Customer may operate the Generation Resource(s) at the site as specified in the Dispatchable Standby Generation Agreement (Agreement).

COMPANY RESPONSIBILITIES

The Company will conduct an analysis of the Customer's Generation Resource and develop a cost estimate for the installation of the equipment necessary for participation under this schedule. The Company will be responsible for providing engineering and funding based on the cost estimate not to exceed the Aid in Construction Allowance. The Company will pay for and own all communications and metering equipment.

The Company will normally pay for all fuel used to operate the Customer's Internal Combustion Generator (s) throughout the term of the Agreement. To the extent the Customer operates the Internal Combustion Generator(s) more than 15 (fifteen) hours per operating year during non-outage periods, the Customer shall be responsible for paying fuel costs, per the Agreement.

In, addition, the Company is responsible for routine maintenance as described in the Agreement. The Company will perform regular testing of the Customer's Generation Resource(s) and control system and testing of the Company's dispatch control and interconnection facilities. The Company will provide power quality monitoring and data reporting of the Customer's facility and Generation Resource(s).

The Company's design will be such that during outage situations, the Customer's Generation Resource(s) will automatically start and provide backup power to the Customer.

SCHEDULE 200 (Continued)

AID IN CONSTRUCTION ALLOWANCE

The Company's Aid in Construction Allowance is based on the cost of Company owned equipment necessary for parallel operations, system protection, safety provisions and communications, related administrative costs and the Generation Resource and switchgear modifications, wiring and conduit necessary to permit Customer's Generation Resource(s) to run in parallel with the Company's system.

PGE shall contribute $39.50 per nominated kW year for Ancillary Services, or $82.40 per nominated kW year for participating in both Demand Response and Ancillary Services. Only BESS resources are eligible to participate in Demand Response. The Customer will be responsible for cost components that bring the total project costs above the Company’s Aid in Construction Allowance. Due to the individual nature of each Generation Resource, specifics on Company Funding and Customer payment responsibilities will be contained in the Agreement.

Upon termination of the Agreement, the Company may remove its equipment.

SPECIAL CONDITIONS

1. The Customer’s charges for Electricity Service under any of the Company’s Standard Service or Direct Access Service schedules are not changed or affected in any way by service under this schedule and are due and payable as specified in those schedules.

2. Parallel operation of Generation Resources must satisfy Company interconnection requirements.

3. The Customer will ensure that the Generation Resource(s), communications equipment, switchgear and metering equipment are accessible to the Company at all times.

4. Prior to receiving service pursuant to this schedule, the Customer and the Company must enter into a written Agreement, signed by the Customer.

5. The Customer must obtain all required permits prior to service initiation to allow all planned operations as specified in the Agreement. The Company will reimburse the Customer for any permits specifically required for this service, including permit renewals during the term of the Agreement up to $10,000 annually.

SCHEDULE 200 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Company may operate the Generation Resource(s) at any time without notice when the Generation Resources are placed on Reserve Status. When advance notice is possible, PGE will notify the Customer as specified in the Agreement.

7. Customers receiving service under this schedule will agree to an initial multi-year term for the Agreement, with options to renew. Should the Customer terminate the Agreement before the end of the initial term, the Customer will reimburse the Company for a portion of the capital investment plus a removal fee as specified in the Agreement.

8. The customer is responsible for maintaining the nominated capacity of the BESS, the details of which are described in the Agreement.

9. PGE may request that the Customer allow PGE to use the Generation Resource(s) in Reserve Status. The decision to allow PGE to use the Generation Resource(s) for any given period of time in Reserve Status is up to the Customer, as specified in the Agreement.

10. The Company will have the right to refuse to fund projects for any reason; including, but not limited to projects deemed high-risk, not cost effective, of poor equipment quality, or an excessive environmental risk. Reasons for funding denial will be provided in writing to the Customer upon request.

SCHEDULE 203
NET METERING SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This schedule is applicable to a Customer with installed generating equipment that qualifies as a Net Metering Facility defined in ORS 757.300(1)(d). Such Customer is referred to as a Customer-generator and defined in OAR 860-039-0005(2)(e). Service under this schedule is provided pursuant to the requirements of OAR 860-039-0005 through 0080 and ORS 757.300.

DEFINITION

Net metering measures the difference between the Electricity supplied by the Company and the Electricity generated by a Customer-generator that is fed back to the Company over an applicable Billing Period. Net Metered generation is supplied to the Company from a Customer that operates an interconnected power production facility using solar power, wind power, fuel cells, hydroelectric power, landfill gas, digester gas, waste, dedicated energy crops available on a renewable basis or low-emission, nontoxic biomass based on solid organic fuels from wood, forest or field residues where the generating nameplate capacity is 2 MW or less for Non-residential Customers and 25 kW or less for Residential Customers. The facility must operate in parallel with the Company's existing Facilities and be primarily intended to offset part or all of the Customer's own electrical requirements.

MONTHLY BILLING

Each Customer-generator will pay monthly charges (including Basic, Demand, Facilities, and Reactive Demand charges) as applicable in accordance with the Customer's service option selection and receive kWh credits as described below.

During a monthly Billing Period when the Company supplies a Customer-generator more energy than the Customer-generator supplies to the Company, the Customer-generator will be charged for the net energy supplied in accordance with the Customer's service option selection.

During a monthly Billing Period when the Customer-generator supplies to the Company more Energy than the Company supplies to the Customer-generator, ("Excess Generation", that is, there is net excess kWh that is delivered to the Company), the Customer will be billed the appropriate monthly charges (including Basic, Demand, Facilities, and Reactive Demand charges as applicable) and will be credited for the net Excess Generation on the next monthly bill as provided for in OAR 860-039-0055(1).

SCHEDULE 203 (Continued)

EXCESS ANNUAL KILOWATT-HOUR CREDITS

In accordance with OAR 860-039-0060, at the end of the last monthly Billing Period of the Customer's-generator annual billing cycle, any excess kWh credits accumulated will be transferred to the Company's low income assistance program at the average annual Schedule 201 Avoided Cost rate. The Customer's excess kWh credits are set to zero for the beginning of the subsequent annual billing cycle. The annual billing cycle begins with the Customer-generator's regularly scheduled April Billing Period (which typically begins in March) and ends with completion of the March Billing Period of the following year unless a different annual billing cycle is mutually agreed to by the Customer-generator and Company and such agreement is provided to the Commission within 30 days.

AGGREGATION AND CREDITING OF EXCESS KILOWATT-HOUR CREDITS WITHIN ANNUAL BILLING CYCLE

As provided in OAR 860-039-0065, upon request from the Customer-generator, the Company will aggregate for billing purposes the monthly kWh usage of the Customer's designated meter and any additional meters of the Customer-generator, where all meters are located on the Customer's contiguous property and are served by the same primary feeder. A 60 day advance notice is required for requests to aggregate meters.

Meters will be aggregated as follows: Generation will first be credited to the designated meter. If there is more generation than consumption at the designated meter, netting will continue with the next meter in the rank order chosen by the Customer. Aggregated meters subject to the same rate schedule as the designated meter must be ranked above any other meters. A change in the rank order used for netting calculations of already aggregated meters is allowed at the beginning of the next annual billing period only and requires a 60 day advance notice.

TIME OF USE

Meters subject to Time of Use rates will be credited as follows: First, generation will be credited in the time period in which it was generated. If there is more generation than consumption in any time period, crediting will continue beginning with the highest rate period first and then continue to lower rate periods, until all generation has been credited. If any generation remains after the crediting process for a meter, it will be applied to lower ranked meters within that month and then to the following month, subject to the processes and annual billing cycle limitations described previously.

SCHEDULE 203 (Concluded)

SPECIAL CONDITIONS

1. Prior to the interconnection of a Net Metering Facility the Customer-generator must submit an application for interconnection review, execute a written Net Metering Agreement and Interconnection Agreement with the Company, and remit any applicable fees and charges as described in Special Condition 8. The Company will review the application in accordance with the requirements of the applicable interconnection facility review set out in OAR 860-039-0030, 0035 and 0040. An applicant may contact the Company's Net Metering Coordinator at (503) 464-8000 or via email at netmetering@pgn.com for net metering service information, applications and agreements.

2. The Customer-generator is responsible for obtaining all necessary government approvals relating to its Net Metering Facility and must meet all applicable building codes and standards including standards specified in OAR 860-039-0020.

3. The Customer-generator is responsible for all costs associated with its Net Metering Facility and is also responsible for all costs related to any modifications to the facility that may be required by the Company resulting from the reviews as provided for in OAR 860-039-0030, 0035 or 0040, as applicable.

4. As provided in OAR 860-039-0015 where applicable, a manual disconnect switch capable of isolating the Net Metering Facility from the Company's system must be provided by the Customer-generator and must be accessible to the Company at all times.

5. The Company maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of day.

6. The Company maintains the right to disconnect, without liability, the Customer-generator for issues relating to safety and reliability.

7. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a Net Metering Facility, or for the acts or omissions of the Customer-generator that cause loss or injury, including death, to any third party.

8. The Company will apply the following fees to each Net Metering Facility interconnection application as provided in OAR 860-039-0045:
   a) For Level 2 interconnection review, $50.00 plus $1.00 per kW of a Net Metering Facilities capacity.
   b) For Level 3 interconnection review, $100.00 plus $2.00 per kW of a Net Metering Facilities capacity.
   c) For Level 2 and 3 interconnections, the reasonable costs for additional engineering and Company system modifications.

SCHEDULE 204
COMMUNITY SOLAR PROGRAM INTERCONNECTION
AND POWER PURCHASE SCHEDULE

AVAILABLE

Service under this schedule is available throughout the Company's Service Territory.

DEFINITIONS

As-Available Rate - is the rate at which PGE will purchase a Project's Net Output that is Unsubscribed Energy as a Qualifying Facility pursuant to PURPA. The As-Available Rate is set forth in PGE's Schedule 201.

Certified Projects - are CSP Projects that have been certified by the Oregon Public Utility Commission of Oregon under OAR 860-088-0050.

Community Solar Program (CSP) - is the program established for the procurement of electricity from CSP Projects pursuant to ORS 757.386, the CSP Rules, and the Program Implementation Manual.

Company - means Portland General Electric Company or PGE.

CSP Interconnection Service - is the interconnection service offered by the Company to qualifying CSP Projects pursuant to this schedule.

CSP Interconnection Application - is the application that a Project Manager must submit to the Company in order to request CSP Interconnection Service.

CSP Project - means a solar photovoltaic energy facility used to generate electric energy on behalf of CSP Participants and for which Participants receive Renewable Energy Credits and credit on their electric bills as provided in the CSP rules, Program Implementation Manual, and this schedule.

CSP Purchase Agreement - means the power purchase agreement between Company and Project Manager that establishes the terms and conditions of the Project Manager's sale and Company's purchase of Net Output from a Certified Project in accordance with this scheduleand the CSP.

CSP Rules - means the administrative rules governing the CSP set forth in OAR Chapter 860, Division 88.

Losses - are the loss of electric energy occurring as a result of the transformation and transmission of electric energy from the Project to the Point of Delivery.

SCHEDULE 204 (Continued)

DEFINITIONS (Continued)

Low-side Metering **-** means loss-compensated revenue metering located on the low voltage sideof the CSP Project's generator step up transformer.

Net Output **-** means all energy expressed in kWhs generated by the CSP Project, less station and other onsite use and less Losses, delivered to the Company in accordance with the conditions of this schedule and the CSP Purchase Agreement. Net Output does not include any environmental attributes. Net Output is comprised of both Subscribed Energy and Unsubscribed Energy.

Participant **-** means a customer of the Company that is either a subscriber or owner of a CSP Project as those terms are defined in ORS 757.386(1), OAR 860-088-0010 and the Program Implementation Manual.

Pre-certified Project **-** is a Project that is pre-certified by the Oregon Public Utility Commission (Commission) under the CSP and in accordance with OAR 860-088-0040 and the Program Implementation Manual.

Program Administrator **-** means the third-party entity directed by the Commission to administer the CSP.

Program Fees **-** are fees that the Company collects on each Participant's utility bill to fund the administration of the CSP in accordance with OAR 860-088-0160(2) and the Program Implementation Manual. Program Fees include a Program Administrator Fee and a Utility Administration Fee. Program Fees, expressed in terms of $/kW/month, are subject to Commission approval and adjusted annually.

Program Implementation Manual **-** means the set of guidelines and requirements for implementing the CSP adopted by the Commission in Order No. 19-438 and which may be changed by the Commission from time to time in future orders.

Project Manager **-** is the entity having responsibility for managing the operation of a CSPProject, as defined in ORS 757.386(1)(d).

PURPA **-** means the Public Utility Regulatory Policies Act of 1978.

Point of Delivery **-** means the high side of the CSP Project's step-up transformer(s) located atthe point of interconnection between the CSP Project and the Company's distribution/transmission system.

SCHEDULE 204 (Continued)

DEFINITIONS (Continued)

Qualifying Facility **-** is a solar photovoltaic facility that meets the PURPA criteria for qualification set forth in Subpart B of Part 292, Subchapter K, Chapter I, Title 18, of the Code of Federal Regulations.

Schedule **-** means this Community Solar Program Interconnection and Power Purchase Schedule, including all exhibits attached hereto or incorporated by reference.

Service Territory **-** means the geographic area within which the Company provides electricity to retail customers, as defined in OAR 806-088-0010(13).

Station Use **-** is electric energy used to operate the CSP Project that is auxiliary to or directly related to the generation of electricity and which, but for the generation of electricity, would not be consumed by the CSP Project.

Subscribed Energy **-** means the portion of the Net Output from a CSP Project delivered to the Point of Delivery for which the Project Manager of the CSP Project has subscribed to Participants and for which the Company must therefore credit the Participants' electric bills as provided in this schedule, the CSP, and the CSP Purchase Agreement.

Supplementary Power **-** is electric energy or capacity supplied by the Company that is regularly used by the CSP Project in addition to the Station Use that the CSP Project supplies itself.

Term **-** means the length of the CSP Purchase Agreement.

Unsubscribed Energy **-** means the portion of the Net Output from a CSP Project delivered to the Point of Delivery for which the Project Manager has not subscribed to Participants and for whichthe Company must therefore purchase from the Project Manager at the As-Available Rate as provided in this schedule and the CSP Purchase Agreement.

SCHEDULE 204 (Continued)

PART 1: CSP INTERCONNECTION

A. Applicable

To a CSP Project that:

1. Is located within the Company's Service Territory;

2. Meets the eligibility requirements of the Community Solar Program Rules and the Program Implementation Manual;

3. Together with all other interconnected and requested generation in the local area, is less than 100 percent of minimum daytime load (MDL), as determined by the Company. If a measure of MDL is not available for the feeder, Company will use 30 percent of summer peak load; and

4. Submits a valid CSP Interconnection Application through the Company's interconnection application online system.

B. CSP Interconnection Process

1. Requesting CSP Interconnection. To request CSP Interconnection, an applicant must submit online through PGE's PowerClerk platform ((https://pgeqf.powerclerk.com) a valid CSP Interconnection Application the Company will process the CSP Interconnection Application in accordance with the CSP Interconnection Procedures provided as Exhibit A tothis schedule.

2. CSP Interconnection Study Process. The Company will study CSP Interconnection requests in accordance with its CSP Interconnection Procedures and using an Energy Resource Interconnection Service study process, as defined in the Company's Open Access Transmission Tariff. However, the Company will also perform a non-binding, informational analysis of the requirements associated with interconnecting the CSP project using its Network Resource Interconnection Service study process, as defined in the Company's Open Access Transmission Tariff. This non-binding Network Resource Interconnection Service analysis will be provided in the same system impact study report as the CSP Interconnection analysis, along with good-faith estimates of both costs and timing of any system upgrades necessary for both types of service.

3. CSP Interconnection Queue. The Company will process CSP Interconnection Applications for prospective CSP Projects in a CSP Interconnection queue, separate from the traditional serial queue. The Company will process all CSP Interconnection Applications in the order received. Requests for CSP Interconnection will be assigned CSP Interconnection queue positions in the order in which the request, and all associated requirements, are received.

SCHEDULE 204 (Continued)

SP Interconnection Process (Continued)

4. Low-side Metering. An applicant may request Low-side Metering for a CSP Project 360 kW and smaller.

5. Joint Study. If an applicant for CSP Interconnection has multiple CSP Projects eligible for interconnection, it can request that the Company study the CSP Projects jointly if the CSP Interconnection Applications are submitted in back to back queue order. Such projects shall equally share in the costs for CSP interconnection study purposes in accordance with the process described in the Interconnection Procedures for CSP Projects, attached as Exhibit A to this Schedule.

C. CSP Interconnection Exhibits

1. The Interconnection Procedures for CSP Projects are set forth in Exhibit A to this Schedule.

2. The System Impact Study Agreement for CSP Projects is set forth in Exhibit B to this Schedule.

3. The Facilities Study Agreement for CSP Projects is set forth in Exhibit C to this Schedule.

4. The CSP Project Completion Form is set forth in Exhibit D to this Schedule.

5. The CSP Project Interconnection Agreement is set forth in Exhibit E to this Schedule.

PART 2: CSP PURCHASE AGREEMENT

A. Applicable

To CSP Projects that:

1. Are located within the Company's Service Territory;

2. Are certified or exempt from certification as a Qualifying Facility;

3. Are pre-certified or Certified as a CSP Project by the Commission under Oregon Administrative Rule (OAR) 860-088-0050; and

4. Except for CSP Projects that have otherwise received consent from the Company, or as otherwise legally required by the Commission, have not already sold, leased assigned, contracted for (including pursuant to the execution of a power purchase agreement under PURPA) or otherwise disposed of the Net Output of the CSP Project, except for the sale of subscriptions for Subscribed Energy to Participants consistent with the CSP.

SCHEDULE 204 (Continued)

B. Contracting Process

Upon request by a CSP Manager, the Company will enter into a CSP Purchase Agreement for the procurement and purchase of Net Output from the Project under and with the following conditions:

1. To obtain a draft CSP Purchase Agreement, the Project Manager must notify the Company of its intent to enter into a CSP Purchase Agreement and provide the Company, in writing, with the general Project information listed below:

   (a) confirmation of Qualifying Facility status (e.g., filed FERC Form 556 certification);
   (b) design capacity (MW), Station Use requirements, and Net Output of power to bedelivered to the Company's electric system;
   (c) solar generation technology and other related technology;
   (d) site location;
   (e) anticipated schedule of monthly power deliveries;
   (f) calculation or determination of minimum and maximum annual deliveries;
   (g) proposed on-line date;
   (h) status of interconnection arrangements; and
   (i) Point of delivery.

2. Upon receipt of complete CSP Project information, the Company will provide a draft CSP Purchase Agreement to the Project Manager for review.

3. When both Company and Project Manager are in full agreement as to all terms andconditions of the draft CSP Purchase Agreement, the Company will prepare and forward to the Project Manager within fifteen (15) business days, a final executable version of the agreement. Following the Project Manager and Company's execution, a completely executed copy of the CSP Purchase Agreement will be returned to the Project Manager.

SCHEDULE 204 (Concluded)

C. CSP Administration

1. Energy Delivery: Once a Certified Project has commenced commercial operation, not later than the second day of each month, the Company shall report to the Program Administrator the amount of Net Output received from the Certified Project at the Point of Delivery for the preceding month.

2. Compensation: As provided in the Program Implementation Manual and the CSP Purchase Agreement, the Company shall provide compensation monthly for each kWh of Net Output accepted at the Point of Delivery as follows:

a. Subscribed Energy: For all Subscribed Energy delivered by the CSP Project to the Company at the Point of Delivery, the Company will apply a bill credit to each Participant's utility bill in accordance with the process and calculations set forth in ORS 757.386(6), OAR 860-088-0170, the Program Implementation Manual, and the CSP Purchase Agreement.

b. Unsubscribed Energy: The Company will pay the Program Administrator on a monthly basis for each kWh of Unsubscribed Energy in the manner described in OAR 860-088-0140, the Program Implementation Manual, and the CSP Purchase Agreement.

3. Program Fees: The Company will apply Program Fees to each Participant's monthly utility bill in the manner described in ORS 757.386, OAR 860-088-0120, the Program Implementation Manual, and PGE's CSP Operational Tariff.

4. Term: The Term of the CSP Purchase Agreement is up to twenty (20) years from the Facility's Commercial Operation Date, in accordance with ORS 757.386(2)(a)(D) and OAR 860-088-0140(1)(a).

D. CSP Purchase Agreement

The form of the CSP Purchase Agreement is provided as Exhibit F of this Schedule.

SCHEDULE 215
SOLAR PAYMENT OPTION PILOT
SMALL SYSTEMS
(10 kW or LESS)

PURPOSE

This schedule establishes a photovoltaic volumetric incentive rate (VIR) pilot program as required by HB 3039 (Chapter 748, Oregon Laws 2009), HB 3690 (Chapter 78, Oregon Laws 2010 Special Session), HB 2893 (Chapter 244, Oregon Laws 2013), and OAR 860-084-0100. The pilot provides payments to retail electricity Customers for electricity generated by permanently installed solar photovoltaic energy systems.

AVAILABLE

To Customers with Qualifying Systems (QSs), as defined in ORS 757.360(3)(b), connected to retail Customers' facilities in territory served by the Company.

APPLICABLE

To Customers that have QSs not purchased with state or ETO incentives with installed nameplate generating capacity 10 kW DC or less where the output is not paid for pursuant to another tariff schedule, that meet the eligibility requirements in OAR 860-084-0120, and where the monthly generation does not exceed Total Monthly Use pursuant to a Solar Photovoltaic Pilot Program and Interconnection Services Agreement (Agreement).

MONTHLY RATE

Customer Charge

The Customer pays the Company a $10.00 Customer Charge per month for each separately metered QS. This is in addition to the Basic Charge for providing Electricity Service to the Customer.

Volumetric Incentive Rate

The Company pays the applicable gross VIR to the QS Customer for eligible generation from the participating Customer with a capacity reservation awarded on or after August 25, 2015.

Description	Hood River County	All Other Counties	
Small : 10 kW or less*	22.7	31.6	¢ per kWh

* DC nameplate capacity

SCHEDULE 215 (Continued)

MONTHLY RATE (Continued)
Volumetric Incentive Rate (Continued)

The gross VIR applies up to the Total Monthly Use and consists of two components: (1) a retail bill offset based on applicable volumetric (kWh) charges, and (2) a net VIR payment. Kilowatt-hours generated in excess of the Total Monthly Use will be carried forward to the next month as provided in OAR 860-084-0360. Total Monthly Use is defined as net kWh from the retail meter (may be positive or negative) plus kWh from the QS meter.

The rate in place at the time of the Reservation Start Date, defined in OAR 860-084-0010(17), applies to the entire 15 year life of the Agreement.

RATE ADJUSTMENT

The Commission may adjust the rate to be effective on October 1 and April 1 of each year consistent with Commission Order Nos. 11-280 and 11-339. For Spring 2015, consistent with Commission Order No 15-092, the Commission adjusted the rate effective date to May 1, 2015. Pursuant to Commission Order No. 15-250, the Commission directs that any remaining capacity be distributed to applicants that are already on the waiting list as part of the May 2015 window. Distribution of any remaining capacity of the VIR program will continue until the earlier of March 31, 2016, or the installation of all program capacity (27.5 MW).

EXCESS ANNUAL KILOWATT-HOUR CREDITS

In accordance with OAR 860-084-0360, at the end of the last monthly Billing Period ending on or before the last day of each generation year, any excess generation kWh credits accumulated will be transferred to the Company's low income assistance program at the average annual Schedule 201 Avoided Cost rate. The default generation year is April 1 through March 31. The Customer's excess kWh credits are set to zero for the beginning of the subsequent annual billing cycle.

SOLAR PHOTOVOLTAIC PILOT PROGRAM AND INTERCONNECTION SERVICES AGREEMENT

The Customer must execute a Solar Photovoltaic Pilot Program and Interconnection Services Agreement with the Company and meet all criteria under OAR Division 84 – Solar Photovoltaic Programs prior to delivery of power to the Company.

In accordance with terms set out in this schedule and the Commission's Rules as applicable, the Customer will receive monthly payment for energy from the Customer's QS based on kWh output, up to Total Monthly Use.

SCHEDULE 215 (Continued)

VIR PAYMENTS

VIR payments under this pilot occur no later than 45 days from the last day of the Customer's billing period. The VIR payment will be reduced by the amount of the retail bill offset for a net VIR payment. The Customer may choose among three payment options for the net VIR payment: (1) receive a direct payment, (2) have payments netted against the Customer's retail bill, or (3) assign the payment to a single assignee. A one-time assignment fee of $25 applies for each payment assignment or reassignment.

The Customer is responsible for the minimum monthly charge and all non-volumetric charges related to the retail electricity rate schedule.

METERING REQUIREMENTS

The Company will install and own the required QS metering equipment at its expense.

Customers served on this schedule must have a PGE-owned meter that measures QS generation net of parasitic load. This meter must be located on the Customer side of the retail meter and on the AC (output) side of the inverter in a location that measures the entire output of the system. The additional meter does not change the Customer's Service Point (SP).

SEMIANNUAL CAPACITY RESERVATION

A customer must apply during the capacity reservation enrollment window beginning at 8 a.m. on April 1 and October 1 of each pilot year. If the 1st occurs on a weekend or holiday, the Company will accept applications on the following business day. For Spring 2015, per OPUC Order 15-092, the enrollment window begins at 8 a.m. on May 1, 2015. Capacity is initially allocated by a 24-hour lottery as directed by Commission Order. After capacity fills, remaining customers will be placed on a waitlist in the order of their reservation. In the event capacity becomes available during the enrollment window, Customers on the waitlist will be offered capacity in that order. The waitlist expires at the end of each enrollment period. The enrollment window is open for three months.

If capacity is not filled in the lottery, then capacity is reserved on a first-come, first-served basis.

A capacity reservation deposit of a $500 minimum or $20 per kW of the proposed system DC nameplate capacity is required with the capacity reservation application. The deposit is refundable unless the capacity reservation expires or the customer cancels the reservation, in each case the applicant forfeits the deposit.

A capacity reservation expires one year from the Reservation Start Date if the system has not been installed or, if an interconnection application is not filed, two months from the Reservation Start Date. See OARs 860-084-0195 through 860-084-0230 for additional capacity reservation rules.

SCHEDULE 215 (Continued)

SPECIAL CONDITIONS

1. Division 84 of the Oregon Administrative Rules (OAR) Chapter 860 contains additional details that apply to this pilot.

2. The QS must be constructed from new components and operational no sooner than July 1, 2010.

3. The Customer-generator is responsible for obtaining all necessary government approvals relating to its QS facility and must meet all applicable building codes and standards including standards specified in OAR 860-084-0260.

4. The Customer-generator is responsible for all costs associated with its QS facility, including interconnection costs incurred by the Company, and is also responsible for all costs related to any modifications to the facility that may be required by the Company resulting from the reviews as provided for in OAR 860-084-0310, 0320 or 0330, as applicable.

5. As provided in OAR 860-084-0340 and where applicable, a manual disconnect switch capable of isolating the QS from the Company's system and accessible to the Company at all times must be provided by the Customer-generator.

6. The estimated kWh output of any QS must not exceed 90% of the actual usage in the most recent 12 billing periods at the premise where the eligible system will be installed. If less than 12 billing periods of actual usage is available at the existing premise or new construction, then the annual usage by a similarly situated Customer may be used or a Customer may submit PGE's load estimation document. The Customer is responsible to determine the appropriate size of the QS.

7. The Customer is not eligible for service under both this schedule and Schedule 203, Net Metering Service for each separately metered account. Each separately metered retail account may only have one QS meter. A Customer is eligible for additional QSs only if the VIR for the additional QS is the same as the first QS.

8. All renewable energy credits (RECs) or other benefits or allowances for which the QS qualifies or creates under current or future law relating to renewable energy are property of the Company.

9. The Company maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of day.

10. The Company maintains the right to disconnect, without liability, the Customer-generator for issues relating to safety or reliability.

SCHEDULE 215 (Concluded)

SPECIAL CONDITIONS (Continued)

11. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a QS, or for the acts or omissions of the Customer-generator that cause loss or injury, including death, to any third party.

12. Participants are required to meet general liability insurance requirements set forth in applicable Solar Photovoltaic Pilot Program and Interconnection Services Agreements in order to protect against injuries to property or persons caused by the QS. The applicable Agreements contain insurance limits and provisions, as well as the basis for making representations of equivalence.

TERM

Each Solar Photovoltaic Pilot Program and Interconnection Services Agreement will have a term of 15 years at the applicable VIR. In accordance with OPUC Order No. 14-025, the pilot will close to new capacity reservations on March 31, 2016, or when the cumulative capacity of contracted systems in the pilot reaches 27.5 MW AC statewide per OAR 860-084-0150, whichever comes first.

SCHEDULE 216
SOLAR PAYMENT OPTION PILOT
MEDIUM SYSTEMS (GREATER THAN 10 kW to 100 kW)

PURPOSE

This schedule establishes a photovoltaic volumetric incentive rate (VIR) pilot program as required by HB 3039 (Chapter 748, Oregon Laws 2009), HB 3690 (Chapter 78, Oregon Laws 2010 Special Session), HB 2893 (Chapter 244, Oregon Laws 2013), and OAR 860-084-0100. The pilot provides payments to retail electricity Customers for electricity generated by permanently installed solar photovoltaic energy systems.

AVAILABLE

To Customers with Qualifying Systems (QSs), as defined in ORS 757.360(3)(b), connected to retail Customers' facilities in territory served by the Company.

APPLICABLE

To Customers that have QSs not purchased with state or ETO incentives with installed nameplate generating capacity greater than 10 kW up to and including 100 kW DC where the output is not paid for pursuant to another tariff schedule, that meet the eligibility requirements in OAR 860-084-0120, and where the monthly generation does not exceed Total Monthly Use pursuant to a Solar Photovoltaic Pilot Program and Interconnection Services Agreement (Agreement).

PARTICIPATION

As determined by Commission Order 11-339, the allocated capacity will be divided between the net metering and competitive bidding options. The enrollment windows will alternate between the net metering and bid options.

A Customer who expects to install a medium system under this schedule has the option to submit a bid in the RFP or a capacity application during corresponding open enrollment periods. Submission of a bid or a capacity application does not guarantee participation in the pilot. Successful bidders and Customers awarded capacity will be notified.

(A) Competitive Bid Option – Request for Proposal

The Company will announce an RFP no later than 30 business days before October 1 for each pilot year or as directed by Commission Order 11-339. Participants will have at least 30 days to submit proposals for a QS including the proposed VIR.

SCHEDULE 216 (Continued)

PARTICIPATION (Continued)

(B) Net Metering Option – Capacity Reservation Enrollment

The Company will accept new capacity reservation applications for program participation on April 1 for each pilot year pursuant to Commission Order 11-339 except in 2015 when the enrollment period starts on May 1. Customers may apply online beginning at 8 a.m. If the 1st occurs on a weekend or holiday, the Company will accept applications on the following business day.

Capacity is initially allocated by a 24-hour lottery or as directed by the Commission. After capacity fills remaining Customers will be placed on a waitlist. The waitlist expires at the end of each enrollment period. The enrollment window is open for three months.

If capacity is not filled in the lottery, then capacity is reserved on a first-come, first-served basis.

VOLUMETRIC INCENTIVE RATE

(A) Competitive Bid Option

The Company pays applicable rates to the QS Customer for eligible generation based on a successful bid from the competitive bidding process.

(B) Net Metering Option

If the customer is awarded capacity during open enrollment, the Company pays the applicable gross VIR for eligible generation from the participating Customer with a capacity reservation awarded on or after August 25, 2015.

Description	Hood River County	All Other Counties	
Medium is >10 kW - 100 kW DC Nameplate Capacity	26.81	25.26	¢ per kWh

Under the net metering option, the gross VIR applies up to the Total Monthly Use and consists of two components: (1) a retail bill offset based on applicable volumetric (kWh) charges, and (2) a net VIR payment. Kilowatt-hours generated in excess of the Total Monthly Use will be carried forward to the next month as provided in OAR 860-084-0360. Total Monthly Use is defined as net kWh from the retail meter (may be positive or negative) plus kWh from the QS meter.

The rate in place at the time of the Reservation Start Date, defined in OAR 860-084-0010(17), applies to the entire 15-year life of the Agreement.

SCHEDULE 216 (Continued)

VOLUMETRIC INCENTIVE RATE (Continued)
Net Metering Option (Continued)

VIR Adjustment

The Commission may adjust the VIR to be effective on April 1 of each year Consistent with Commission Order Nos. 11-280 and 11-339. For Spring 2015, per OPUC Order 15-092, the enrollment window begins at 8 a.m. on May 1, 2015. Pursuant to Commission Order No. 15-250, the Commission directs that any remaining capacity be distributed to applicants that are already on the waiting list as part of the May 2015 window. Distribution of any remaining capacity of the VIR program will continue until the earlier of March 31, 2016, or the installation of all program capacity (27.5 MW).

VIR Payments

VIR payments under this pilot occur no later than 45 days from the last day of the Customer's billing period. The VIR payment will be reduced by the amount of the retail bill offset for a net VIR payment. The Customer may choose among three payment options for the net VIR payment:
(1) receive a direct payment,
(2) have payments netted against the Customer's retail bill, or
(3) assign the payment to a single assignee.

Excess Annual Kilowatt-hour Credits

In accordance with OAR 860-084-0360, at the end of the last monthly Billing Period ending on or before the last day of each generation year, any excess generation kWh credits accumulated will be transferred to the Company's low income assistance program at the average annual Schedule 201 Avoided Cost rate. The default generation year is April 1 through March 31. The Customer's excess kWh credits are set to zero for the beginning of the subsequent annual billing cycle.

CUSTOMER COSTS

Capacity Reservation Deposit

The Customer pays a deposit of $500 minimum or $20 per kW of the proposed system capacity at the time of enrollment or bid submission. The deposit is refundable unless the capacity reservation expires or the Customer cancels the reservation, in each case the applicant forfeits the deposit.

Customer Charge

The Customer pays the Company a $10.00 Customer Charge per month for each separately metered QS. This is in addition to the Basic Charge for providing Electricity Service to the Customer. The VIR payment will be reduced by the Customer Charge under this schedule.

SCHEDULE 216 (Continued)

CUSTOMER COSTS (Continued)

Assignment Fee

The Customer may assign the net VIR payment each month to a single assignee and the Company will make the payment to the assignee. A one-time assignment fee of $25 applies for each payment assignment or reassignment.

Interconnection Review Fee

For an interconnection review, a fee may apply as provided in OAR 860-084-0320 and 0330. Other costs may apply for modifications to the electric distribution system or for additional review.

Level 1	No charge applies
Level 2	up to $50.00 plus $1.00 per kW of the Qualifying System's capacity
Level 3	up to $100.00 plus $2.00 per kW of the Qualifying System's capacity

SOLAR PHOTOVOLTAIC PILOT PROGRAM AND INTERCONNECTION SERVICES AGREEMENT

The Customer must execute a Solar Photovoltaic Pilot Program and Interconnection Services Agreement with the Company and meet all criteria under OAR Division 84 – Solar Photovoltaic Programs prior to delivery of power to the Company.

METERING REQUIREMENTS

The Company will install and own the required QS metering equipment at its expense.

(A) Competitive Bid Option

Customers served under this option must be separately metered from all other load and generation and operate in parallel with the Company's distribution system.

(B) Net Metering Option

Customers served under this option must have a PGE-owned meter that measures QS generation net of parasitic load. This meter must be located on the Customer side of the retail meter and on the AC (output) side of the inverter in a location that measures the entire output of the system. The additional meter does not change the Customer's Service Point (SP).

SCHEDULE 216 (Continued)

SPECIAL CONDITIONS

1. Division 84 of the Oregon Administrative Rules (OAR) Chapter 860 contains additional details that apply to this pilot.

2. The QS must be constructed from new components and operational no sooner than July 1, 2010.

3. The Customer-generator is responsible for obtaining all necessary government approvals relating to its QS facility and must meet all applicable building codes and standards including standards specified in OAR 860-084-0260.

4. The Customer-generator is responsible for all costs associated with its QS facility, including interconnection costs incurred by the Company, and is also responsible for all costs related to any modifications to the facility that may be required by the Company resulting from the reviews as provided for in OAR 860-084-0310, 0320 or 0330, as applicable.

5. As provided in OAR 860-084-0340 and where applicable, a manual disconnect switch capable of isolating the QS from the Company's system and accessible to the Company at all times must be provided by the Customer-generator.

6. Under the net metering option the estimated kWh output of any QS must not exceed 90% of the actual usage in the most recent 12 billing periods at the premise where the eligible system will be installed. If less than 12 billing periods of actual usage is available at existing premise or new construction, then the annual usage by a similarly situated Customer may be used or a Customer may submit PGE's load estimation document.

7. The Customer is not eligible for service under both this schedule and Schedule 203, Net Metering Service for each separately metered account. Each separately metered retail account may only have one QS meter. A Customer is eligible for additional QSs only if the VIR for the additional QS is the same as the first QS.

8. All renewable energy credits (RECs) or other benefits or allowances for which the QS qualifies or creates under current or future law relating to renewable energy are property of the Company.

9. The Company maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of day.

SCHEDULE 216 (Concluded)

SPECIAL CONDITIONS (Continued)

10. The Company maintains the right to disconnect, without liability, the Customer-generator for issues relating to safety or reliability.

11. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a QS, or for the acts or omissions of the Customer-generator that cause loss or injury, including death, to any third party.

12. Participants are required to meet general liability insurance requirements set forth in applicable Solar Photovoltaic Pilot Program and Interconnection Services Agreements in order to protect against injuries to property or persons caused by the QS. The applicable Agreements contain insurance limits and provisions, as well as the basis for making representations of equivalence.

TERM

Each Solar Photovoltaic Pilot Program and Interconnection Services Agreement will have a term of 15 years at the applicable VIR. In accordance with OPUC Order No. 14-025, the pilot will close to new capacity reservations on March 31, 2016, or when the cumulative capacity of contracted systems in the pilot reaches 27.5 MW AC statewide per OAR 860-084-0150, whichever comes first.

SCHEDULE 217
SOLAR PAYMENT OPTION PILOT
LARGE SYSTEMS (GREATER THAN 100 kW to 500 kW)

PURPOSE

This schedule establishes a photovoltaic volumetric incentive rate (VIR) pilot program as required by HB 3039 (Chapter 748, Oregon Laws 2009), HB 3690 (Chapter 78, Oregon Laws 2010 Special Session), HB 2893 (Chapter 244, Oregon Laws), and OAR 860-084-0100. The pilot provides payments to retail electricity Customers for electricity generated by permanently installed solar photovoltaic energy systems. Capacity under this schedule is awarded based on an annual competitive bidding process.

AVAILABLE

To Customers with Qualifying Systems (QSs), as defined in ORS 757.360(3)(b) located on retail Customers' property in territory served by the Company.

APPLICABLE

To Customers that have QSs not purchased with state or ETO incentives with installed nameplate generating capacity over 100 kW up to and including 500 kW DC where the output is not paid for pursuant to another tariff schedule and that meet the eligibility requirements in OAR 860-084-0120.

MONTHLY RATE

Customer Charge

The Customer pays the Company a $10.00 Customer Charge per month for each separately metered QS.

Volumetric Incentive Rate

The Company pays applicable rates to the QS Customer for eligible generation based on a successful bid from the competitive bidding process.

SOLAR PHOTOVOLTAIC PILOT PROGRAM AND INTERCONNECTION SERVICES AGREEMENT

The Customer must have a successful bid in the Request for Proposal (RFP) process, execute a Solar Photovoltaic Pilot Program and Interconnection Services Agreement with the Company, and meet all criteria under OAR Division 84 – Solar Photovoltaic Programs prior to delivery of power to the Company. The Customer must certify that they eligible to make wholesale sales of energy at market-based rates.

In accordance with terms set out in this schedule and the Commission's Rules as applicable, the Company will provide the Customer with a photovoltaic VIR payment for energy made available from the Customer's QS.

SCHEDULE 217 (Continued)

VIR PAYMENTS

The VIR payment will be reduced by the Customer Charge under this schedule. The Customer may assign the net VIR payment each month to a single assignee and the Company will make the payment to the assignee. A one-time assignment fee of $25 applies for each payment assignment or reassignment.

METERING AND INTERCONNECTION REQUIREMENTS

Customers served on this schedule must be separately metered from all other load and generation and operate in parallel with the Company's distribution system.

REQUEST FOR PROPOSAL

The Company will announce an RFP for each pilot program year. Participants will have at least 30 days to submit proposals for a QS including the proposed VIR.

ANNUAL CAPACITY RESERVATION

The Customer must submit an application package meeting the requirements of OAR 860-084-0230(2). A capacity reservation deposit of $20 per kW of the proposed system DC nameplate capacity is required with the capacity reservation application. The deposit is refundable unless the capacity reservation expires or the Customer cancels the reservation, in each case the applicant forfeits the deposit.

Capacity reservations under this schedule are awarded annually based on competitive bidding. The capacity reservation begins when the bidder is notified of a successful bid. Notification will occur within 15 business days after the bidding response deadline based on least bid VIRs and available capacity.

A capacity reservation expires two months from the Reservation Start Date if an interconnection application is not filed. If an interconnection application has been filed, the capacity reservation expires six months from when the interconnection application is filed or one year from the Reservation Start Date if the system has not been installed, whichever is longer. See OARs 860-084-0195 through 860-084-0230 for additional capacity reservation rules.

ANNUAL CAPACITY RESERVATION LIMITS

The Company will award bids annually up to the periodic available capacity, pursuant to Commission Order 10-198.

SCHEDULE 217 (Continued)

INSURANCE

Participants are required to meet general liability insurance requirements set forth in the applicable Solar Photovoltaic Pilot Program and Interconnection Service Agreements in order to protect against injuries to property or persons caused by the QS. The applicable Agreements contain insurance limits and provisions, as well as the basis for making representations of equivalence.

SPECIAL CONDITIONS

1. Division 84 of the Oregon Administrative Rules (OAR) Chapter 860 contains additional details that apply to this pilot.

2. The QS must be constructed from new components and operational no sooner than July 1, 2010.

3. The Customer-generator is responsible for obtaining all necessary government approvals relating to its QS facility and must meet all applicable building codes and standards including standards specified in OAR 860-084-0260.

4. The Customer-generator is responsible for all costs associated with its QS facility, including interconnection costs incurred by the Company, and is also responsible for all costs related to any modifications to the facility that may be required by the Company resulting from the reviews as provided for in OAR 860-084-0310, 0320 or 0330, as applicable. The Company provides the QS meter.

5. As provided in OAR 860-084-0340 and where applicable, a manual disconnect switch capable of isolating the QS facility from the Company's system must be provided by the Customer-generator and will be accessible to the Company at all times.

6. All renewable energy credits (RECs) or other benefits or allowances for which the QS qualifies or creates under current or future law relating to renewable energy are property of the Company.

7. The Company maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of day.

8. The Company maintains the right to disconnect, without liability, the Customer-generator for issues relating to safety or reliability.

SCHEDULE 217 (Concluded)

SPECIAL CONDITIONS (Continued)

9. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a QS, or for the acts or omissions of the Customer-generator that cause loss or injury, including death, to any third party.

10. The Company will apply the following fees to each QS interconnection application as provided in OAR 860-084-0320, 0330:
    a) For Level 2 interconnection review, $50.00 plus $1.00 per kW of a QS facility capacity.
    b) For Level 3 interconnection review, $100.00 plus $2.00 per kW of a QS facility capacity.
    c) For Level 2 and 3 interconnections, the reasonable costs for additional engineering and Company system modifications.

11. Pursuant to Commission Order No. 14-025, there is no enrollment window in October 2014. However, a new window will start May 1, 2015 to “clean up” the remaining capacity.

TERM

Each Solar Photovoltaic Pilot Program and Interconnection Services Agreement will have a term of 15 years at the applicable VIR. In accordance with OPUC Order No. 14-025 The VIR pilot program will close to new capacity reservations March 31, 2016 or when the cumulative capacity of contracted systems in the pilot reaches 27.5 MW AC statewide per OAR 860-084-0150, whichever comes first.

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)

4.5% 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)	$260.00
Returned Payment Charge	$ 25.00
Special Meter Reading Charge (non-network)	$ 25.00
Meter Test Charge	$ 140.00
Late Payment Charge (monthly)	2.2% of delinquent balance
Field Visit Charge (2)	$ 50.00
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 201Qualifying Facility 10 MW or Less	$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.

SCHEDULE 300 (Continued)

CREDIT RELATED DISCONNECTION AND RECONNECTION RATES (Rule H)

Disconnects	
Monday through Friday	No charge
Reconnection	
Standard Reconnection	
At Meter Base	$ 50.00
Other than Meter Base	$145.00
After Hours Reconnection(1)	
At Meter Base	$190.00
Other than Meter Base	$370.00

CUSTOMER REQUESTED DISCONNECTION AND RECONNECTION RATES (Rule H)(2)(3)

Disconnects	
Standard	
At Meter Base	No charge
Other than Meter Base	No charge
Reconnects	
Standard	
Safety related	No charge
Non-safety related	
At Meter Base	$ 50.00
Other than Meter Base	$145.00

(1) PGE representatives will be dispatched to reconnect service until 7:00 p.m., Monday through Friday. As such, crews dispatch up to and including 7:00 p.m. may be reconnecting service after 7:00 p.m. State- and utility-recognized holidays are excluded from the after hours provision.
(2) These rates apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In other cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.
(3) No charge for disconnects / reconnects completed to ensure safe working conditions that meet the guidelines in Rule H(4).

SCHEDULE 300 (Continued)

PULSE OUTPUT METERING (Rule M)

Installation of Standard Meter Option (1 or 2 outputs)	$ 350.00
Installation of Complex Meter Option (1 – 4 outputs)	$1,300.00

NON-NETWORK RESIDENTIAL METER RATES (Rule M)

Installation of non-network meter (one time charge)	$140.00
Non-network Meter Read	$25.00 per month

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, that require submersible transformers, the charge will be the calculated difference in cost between submersible and pad mount transformer installations including the costs of future maintenance

SCHEDULE 300 (Continued)

TRANSFORMERS

Transformer Content

Upon request, PGE will research its records to provide a customer with Polychlorinated Biphenyls (PCB) content of a PGE transformer. Records searches could reveal the PCB content in specified transformer or that the PCB content is unknown. In the situation where the PCB content is unknown, an additional request can be made to test the PCB concentration.

Research Transformer PCB Content	
PCB Content-Specific Transformer	$82.00 per Transformer[(1)]
Additional Request	
Concentration Test	site-by-site basis[(2)]

PCB Records Request

To request a records search to determine the PCB content of PGE equipment, please contact PGE's Environmental Services to request a PCB Inquiry form. The form can be sent electronically or by postal service, if needed. Complete the form and return it, along with payment to: PGE PCB Inquiry, 121 SW Salmon Street, WTCBR05, Portland, OR 97204. Checks are made payable to PGE PCB Inquiry and submitted with the PCB Inquiry form.

(1) PGE transformers often have stickers which indicate the PCB concentration of the oil within that transformer. The Customer may determine the content by observing the sticker. The PCB content of equipment with green stickers is unknown. However, blue stickers indicate <1 parts per million (PPM) PCB, red stickers indicate <15 ppm PCB, and black stickers indicate <48 ppm PCB.

(2) The additional cost of testing PCB concentration is determined on a site-by-site basis, and based on whether the following activities are required: de-energizing equipment, collecting samples, contracting sample analyses, and preparation of a summary report. In some instances, a proposal from a contractor may be required.

SCHEDULE 300 (Continued)

LINE EXTENSIONS (Rule I)

Line Extension Allowance (Section 1)[1]

Residential Service All Electric[2]	$2,260.00 / dwelling unit
Residential Service Primary Other[3]	$1,590.00 / dwelling unit
Schedule 32	$0.2564 / estimated annual kWh
Schedules 38 and 83	$0.1050 / estimated annual kWh
Schedules 85 and 89 Secondary Voltage Service	$0.0778 / estimated annual kWh
Schedules 85 and 89 Primary Voltage Service	$0.0429 / estimated annual kWh
Schedules 15, 91 and 95 Outdoor Lighting	$0.1529 / estimated annual kWh
Schedule 92 Traffic Signals	$0.0424 / estimated annual kWh
Schedules 47 and 49	$0.0980 / estimated annual kWh

Trenching or Boring (Section 2)

Trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits	Estimated Actual Cost

Lighting Underground Service Areas

Installation of conduit on a wood pole for lighting purposes	Estimated Actual Cost

(1) Estimated annual kWh values used to calculate non-Residential Customer line extension allowances do not reflect onsite generation.

(2) Residential All Electric Service is a dwelling where the primary heating is provided by an active electric HVAC-system. Common qualifying system include but are not limited to stand-alone ducted heat pumps, ducted heat pumps with auxiliary electric resistant heat strips, ductless mini-splits, and packaged terminal air conditioners. Electric resistant heat strips, baseboards, and electric resistant in-wall heaters are allowed as back-up heat source. Dwellings heated solely by electric resistance heating systems without a primary qualifying electric heating system are excluded from the Residential All Electric Service Line extension allowance.

(3) Residential Service Primary Other is a dwelling where the primary heating source is provided by an alternative HVAC-system that uses heating fuels such as natural gas, propane, oil, and biodiesel. Common qualifying HVAC-systems include but are not limited to stand-alone combustion furnaces, combustion furnaces with air conditioners, combustion furnaces with heat pumps, as well as gas boilers. Dwellings heated primarily by electric resistance heating and passive means also fall into this category.

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	$ 180.00

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$1,146.00
Permanent Customer obtained	
Overhead Service	$670.00
Underground Service	$672.00
Existing service	$870.00

Enhanced Temporary Service

Fixed fee for initial 6-month period	$963.00
Fixed fee per 6-month renewal	$415.00

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 307
RESIDENTIAL BILL ASSISTANCE PROGRAM

PURPOSE

The purpose of this schedule is to implement the Residential Bill Assistance Program consistent with Commission Order No. 20-401. The Order directs Utilities to establish a program to identify and manage residential customer arrearages associated with the COVID-19 pandemic to proactively assist residential customers prior to resuming disconnections and prevent bad debt accumulating on utility accounts.

The program may identify and waive residential arrearages at an initial total amount of $17,557,000. This amount represents one percent of the Company's 2019 Oregon retail revenues, not to be increased without prior Commission approval. The Company is seeking Commission approval to add an additional amount of $6 million in program funds to continue offering the Customer Assistance and Reconnect Assistance, and the revised Extended Match programs described below.

AVAILABLE

In all territory served by the Company.

APPLICABLE

This program is only available to Residential Customers.

ELIGIBILITY

The PGE Bill Assistance Program will be eligible to Residential Customers at least 31 days in arrears.

ENROLLMENT

Eligible Residential Customers may enroll in a bill assistance plan by calling PGE Customer Service, Monday through Friday, 7 a.m. to 7 p.m. at 503-228-6322 or 800-542-8818.

BILL ASSISTANCE OPTIONS

Several options are available to assist Residential Customers manage bills regardless of account status. The program's intent is to help customers catch up on past due balances or get reconnected if they've been disconnected for non-payment. Programs are designed to match Customer payments anywhere from a one-time match up to a match for 12-months as well as provide one-time assistance for those unable to make a payment. The maximum amount of bill assistance per Customer is $1,000 for all programs combined, including Customer Assistance. All programs will be available for a limited time based on funding availability. Programs are outlined below:

SCHEDULE 307 (Continued)

BILL ASSISTANCE OPTIONS (Continued)

1. 50/50 Plan – One-time Company bill payment to match Customer payment of an equal amount. To qualify, the Customer must be at least 31 days past due on payments. The Company match will not leave a credit on the Customer account. This program will be closed to new entrants after the initial $17.5 million in funding is fully subscribed.

2. Payment Match –Three-month Company bill payment plan to match Customer payments of equal amounts. To qualify, the Customer must be at least 31 days past due on payments. Matching stops after three months or when total account balance reaches $0. This program will be closed to new entrants after the initial $17.5 million in funding is fully subscribed.

3. Extended Match Program – Company bill payment plan to match Customer payments for up to 12 months. Customer must enroll in a Time Payment Arrangement (TPA) plan, up to 24-months, to match payments up to the first 12 months of a TPA. To qualify, the Customer must be at least 31 days past due on payments. Matching stops after 12 months, when total account balance reaches $0 or if the Customer is disconnected. Extended Match Program enrollments will end once up to 50% of the additional $6 million funding is allocated or October 31, 2021 which ever happens sooner.

4. Customer Assistance – One-time Company bill payment, up to $500, to help Customers get current on their balance utilizing an instant grant. This assistance will be made available to Customers who are unable to get current without assistance. This assistance will also cover any remaining Customer balance after receiving energy assistance, up to $500. Customer Assistance funds will not leave a credit on the account.

5. Reconnect Assistance – One-time Company bill payment, up to $500, to assist in reconnecting disconnected Customers. Company will also offer enrollment in TPA plan up to one year. Customers that used one of the other options previously are eligible.

SCHEDULE 307 (Concluded)

SPECIAL CONDITIONS

1. The Company will defer and seek recovery of all associated program costs not otherwise included in rates in accordance of Commission Order No. 20-376. The additional $6 million in funding is also subject to deferred accounting and will be added to the balance of COVID-related deferred costs.

2. Additional programs or adjustments to the programs listed above may occur as we develop experience in operating these programs, upon Commission approval.

3. In addition to the reporting requirements outlined in Commission Order No. 20-401, the Company will provide quarterly reporting on the amount of assistance that has been provided and the number of customers enrolled by program, including cost to operate the program. Additional reporting may be provided as determined by the Commission.

TERM

The duration of this program is through December 31, 2022, until the Company reaches the spending limit, or until the Commission closes the program.

SCHEDULE 320
METER INFORMATION SERVICES

PURPOSE

This schedule provides Meter Information Services to Nonresidential Customers and with customer permission, to the Energy Trust of Oregon.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers and the Energy Trust of Oregon (ETO).

PROGRAM DESCRIPTION

Meter Information Services provides Nonresidential Customers with interval usage data depicted in charts and graphs. This service enables Nonresidential Customers to compare their current usage with historic data, identify anomalies in their usage, track savings from energy efficiency projects and understand their energy usage.

Nonresidential Customers requesting service under this schedule must have the ability to access the appropriate websites or to capture and translate provided interval usage data. The Energy Trust of Oregon will use the service with Customers on energy efficiency measures. The Company will advise the Customer and the ETO on equipment specifications and subsequent changes necessary to meet these service requirements.

BILLING RATES

Meter Information Services is billed monthly on the Customer's bill for Electricity Service. Customers may choose to be separately billed for Meter Information Services for an additional $8 per bill.

SCHEDULE 320 (Continued)

BILLING RATES (Continued)

Standard Package

Set Up Fee*:	$350.00 for the first meter $150.00 for each additional meter $75.00 for 50 or more meters
	A set-up fee is to be waived if a customer is transferred from a product that is no longer offered.

Monthly Fees per meter:

1 to 5 meters	$70.00
6 to 10 meters	$65.00
11 to 15 meters	$60.00
16 to 20 meters	$55.00
21 to 49 meters	$50.00
50 or more meters	$45.00

Additional Customer Support or Training: $125.00 per hour

Customized service, data, and hardware, including but not limited to Data loggers, Data Recorders, Energy Kiosks, Natural gas data, Interval Data via File Transfer Protocol (FTP) to Third Party*, and Raw Feeder Data may be provided at a mutually agreed, cost based price.

SPECIAL CONDITIONS

1. Customers who request service both inside and outside of the service territory will have all Service Points (SPs) receiving service on this Schedule, added together to determine the appropriate monthly rate per meter.

2. Service under this schedule requires interval metering and meter communications be in place prior to the initiation of Meter Information Services.

3. Because of the meter and/or software installation required for this service, the Company anticipates a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.

4. Meter Information Services requires that the Customer have certain minimum computer system requirements and an ability to capture and transmit interval usage data. Specifications will be provided upon request. The Customer will, at its expense, provide the necessary communications equipment.

* No new service for Interval Data via FTP to Third Party. FTP is used to send/receive files from a remote computer. See Special Condition 9.

SCHEDULE 320 (Concluded)

SPECIAL CONDITIONS (Continued)

5. The ETO will be supplied data only after the Customer provides to the Company a signed release form by the Customer giving the ETO access to interval data, account information, and software application. The ETO will also complete an Energy Information Services (EIS) order form and sign a contract or otherwise document agreement specifying price, billing and duration of service. The EIS order form is available on PGE’s web site.

6. Customers may request a submeter be installed for the purpose of receiving Meter Information Services from a specified location behind the Company meter. However, the feasibility of installing a submeter will be at the Company’s discretion. Customers choosing submetering will incur charges for all associated labor and materials needed to install the meter. The Customer is responsible for ownership and maintenance of the submeter.

7. This product is provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 860-038-0640 with the exception of OAR 860-38-0540 with which the Company received a waiver from the Commission. The waiver will be reconsidered, if justified, based on an examination of inquiries from competitors or potential competitors.

8. The Company will disclose to Customers in any written or electronic marketing communications of more than minor length that the Customer may procure similar services from other providers.

9. Interval Data via FTP to Third Party is not being offered at this time. The Interval Data via FTP will still be available to those customers receiving service as of September 29, 2017. The Interval Data is closed to new service during the implementation of the new Customer Information System (CIS) and meter data management system (MDMS).

SCHEDULE 328
CLEAN FUELS CREDIT MONETIZATION OPTIONAL SERVICE

PURPOSE

To support customer participation in Transportation Electrification and facilitate access to State of Oregon's Clean Fuels Program (CFP) administered under Oregon Administrative Rules Chapter 340, Division 253 by offering CFP credit monetization services.

AVAILABILE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers who are eligible CFP credit generators under Oregon Department of Environmental Quality (DEQ) rules.

CHARACTER OF SERVICE

The Company, or its representative, will monetize CFP credits (credits) for Customers. The service includes: calculation of carbon intensity of fuel supply; equipment registration; as well as credit aggregation, credit claiming, credit transfer, credit tracking, and credit reporting for base credits, incremental credits, and advance credits in compliance with Oregon's CFP rules and regulations.

RATES FOR SERVICE

PGE will charge the participating Customer all applicable transaction fees, plus an administrative fee that covers the utility's administrative costs associated with DEQ compliance and monetizing credits. The administrative fee is calculated based on fleet vehicle size, vehicle type, number of chargers, charger utilization, and quantity of credits sold, and will be charged on a nondiscriminatory basis to participating customers, based on those factors.

SPECIAL CONDITIONS

1. PGE will monetize credits on behalf of the Nonresidential customer that has signed a contract, by leveraging PGE's existing market and Clean Fuels compliance infrastructure.

2. PGE makes no guarantee as to a certain monetized value of the CFP credits. PGE is not responsible for market fluctuations which may affect credit value or amounts.

SCHEDULE 328 (Concluded)

SPECIAL CONDITIONS (Continued)

3. The administrative fee is designed to include all administration expenses, including, but not limited to: DEQ registration, data pulls, data reporting, market transaction cost, record keeping, billing, management and providing Internal Revenue Service tax reporting information. PGE will update fees as needed to appropriately reflect the costs associated with this service.

4. The administrative fee will be applied after CFP credit sales, and on no less than an annual basis. PGE will remit to the customer the net amount after the administrative fee is deducted.

SCHEDULE 339
ON-BILL LOAN REPAYMENT SERVICE
CLEAN ENERGY WORKS OF OREGON PROGRAM

PURPOSE

This schedule describes the general terms of the On-Bill Loan Repayment Service that PGE will provide in support of the Energy Efficiency and Sustainable Technologies Act of 2009 (EEAST) legislation (HB2626) and offered by Clean Energy Works Oregon (CEWO). The program will enable homeowners to access low-interest; long-term financing for energy efficiency measures with repayment of the Loan using PGE's On-Bill Loan Repayment Service. Loan repayment amounts will be included and separately stated on the participating Customer's Electricity bill.

AVAILABLE

To all participating Customers served by the Company within its Service Territory.

APPLICABLE

To the primary Customer of Record of any owner-occupied electrically heated single family premises participating in the Clean Works of Oregon program and agreeing to utilize the Company's Electricity bill for repayment of the Loan amount. Participation is dependent on the Customer having continuous Electricity Service with the Company during the period the bill is used for repayment of the loan.

SERVICE DESCRIPTION

CEWO will act as a coordinator between utilities, Energy Trust of Oregon, and financing organizations. PGE will exchange data, submit invoices for services rendered, and remit loan payments received to CEWO. CEWO will in turn communicate with the various financing organizations.

The On-Bill Loan Repayment Service provides limited billing and remittance activity as described in this Schedule.

The On-Bill Loan Repayment Service:

The Company will add to a participating Customer's Electricity bill a separately stated fixed Loan repayment amount as determined by CEWO and communicated to the Company. The On-Bill Loan Repayment Service will remain in effect on a Customer's account until such time that the Company receives notice from CEWO to discontinue the repayment item, or that the repayment obligation is satisfied, or if Electricity Service at the premises is terminated (whether such termination is initiated by the Company or by the Customer of Record), or if payment for this On-Bill Loan Repayment Service is not received by the Company.

SCHEDULE 339 (Continued)

SERVICE DESCRIPTION (Continued)

CEWO is responsible for qualifying Customers for loans and establishing a contractual relationship with the Customer for repaying the Loan. CEWO will obtain and provide upon request to the Company, the participating Customer's written authorization that allows the repayment amount to be placed on the Customer's Electricity bill and authorizes the Company to share the participating Customer's account payment history and credit activity with CEWO on an as needed, ongoing basis.

The On-Bill Loan Repayment Service program is offered with the following understanding:

Related to the Participating Customer:

1. The Customer's decision to enter into a Loan agreement with CEWO will not affect his/her ability to establish credit with the Company; nor impact the deposit amount that the Customer may be required to pay, or affect the Customer's ability to receive reliable Electricity Service.

2. Customer payments remitted to the Company shall first be applied to those charges related to the provision of Electricity Service and other related services billed to the Customer consistent with the Company's tariff[1]. Any underpayment of the monthly loan amount will be added to the subsequent bill. Overpayments received by the Company will not be applied to the CEWO Loan balance, nor will refunds be issued. The overpayment will be applied towards Electricity Service charges in the same posting priority as defined within the Company's tariff[2].

3. The Company will not disconnect a Customer's service for non-payment of the CEWO Loan amount. The Company retains all rights and responsibilities regarding the provision of Electricity Service separate from the CEWO Loan Repayment including disconnection for non-payment of Electricity Service charges.

4. Time Payment Agreements or other payment arrangements will not be available for the CEWO Loan amount, nor will Energy Assistance payments be applied to this Service.

5. Delinquency Conditions: The Company will not provide a collections service for delinquent CEWO Loan amounts, provide past due notices or disconnection of service for non-payment or late payment of these loans, nor will the Company assess, or collect, late fees on the Loan balance for CEWO. A return check charge as provided in Schedule 300 will be applied to any payment returned by a financial institution.

1) Rule F, Billings, (5), Presentation and Payment of Bills
2) Should the overpayment be equal to that of the remaining CEWO Loan balance, the Company may issue a refund and advise the Customer to contact the lending agent CEWO on proper loan pay-off procedures.

SCHEDULE 339 (Continued)

SERVICE DESCRIPTION (Continued)

6. If the Customer sells the property, the loan will revert to CEWO and its financing organization. CEWO may work with the new homeowner to continue the loan; if the new homeowner is willing to continue the loan CEWO and PGE will treat this as a new loan for future use.

Related to the CEWO:

1. The Company will not seek to recover incremental costs associated with this program from its Customers. All programming costs, credit searches, loan set up costs and marketing costs that the Company incurs are the sole responsibility of CEWO.

2. The Company will transfer to CEWO on-going remittance via an agreed means not less than on a monthly basis that includes the aggregate amount of all CEWO repayment amounts received during the previous month, a listing of participating Customers, payment amounts and dates of payment and other information as agreed to between the Company and CEWO.

3. Any Customer payment transferred by the Company to CEWO that is later returned by the Customer's financial institution will be withheld from the subsequent payment to CEWO. CEWO may not assess a return payment fee to the Company.

4. The Company will not transfer a CEWO Loan to another Customer without first receiving notification from CEWO that a new qualifying Customer at the premises has established a contract with CEWO for repayment of the CEWO Loan and has authorized the Company to provide the On-Bill Loan Repayment Service.

5. Dispute Resolution: CEWO must provide the Company with a toll-free customer service phone number to which the Company can refer Customers who have questions or concerns about their CEWO Loan. The Company is not responsible for responding to Customer questions and disputes related to CEWO or for any misinformation provided by CEWO.

SPECIAL CONDITIONS

1. Participating Customers shall acknowledge that the Company will be held harmless from any cost, liability, claim, suit and expense arising out of any act or omission of the CEWO, its financing organizations or contractors related to the installation of energy efficiency measures, the effectiveness of such installations or resulting energy or financial savings, any representations made directly or indirectly to Customers concerning energy usage, environmental impacts, property values or other effects or savings related to the energy efficiency measures, including but not limited to the negligent or wrongful acts or omissions of contractors with regard to the installation of energy efficiency upgrades resulting from or related to this repayment activity.

SCHEDULE 339 (Concluded)

SPECIAL CONDITIONS (Continued)

2. The provision of repayment services provided by the Company will not affect the Company's adherence to Utility Regulation and law, Oregon Administrative Rules or Division 21 rules and regulation.

3. The Company may withdraw from providing repayment loan activity at any time after receiving three months written notice by CEWO. If notice to terminate has not been provided, service under this Tariff will automatically terminate once CEWO has terminated their Operating Agreement with the Company.

4. The standards and requirements under PGE's Customer Service and Billing Service Quality Measures shall not apply with respect to bills and remittances related to this repayment loan activity.

TERM

This tariff will be in effect through December 31, 2012 or through such time that Legislation either terminates or changes the requirements regarding this Service.

SCHEDULE 340
ON-BILL REPAYMENT SERVICE
ENERGY EFFICIENCY AND SUSTAINABLE TECHNOLOGIES (EEAST)

PURPOSE

This Schedule describes the general terms of the On-Bill Repayment Service that PGE provides in compliance with the Energy Efficiency and Sustainable Technologies (EEAST) legislation codified as ORS 470.500 through ORS 470.720. This Service will enable Customers access to low-cost, long-term financing for installed energy efficiency measures with repayment on the Customer's PGE Electricity bill. Financing for the Customer's energy efficiency measures is provided by a third party financial institution. The Customer's repayment amount will be included and separately stated on the participating Customer's Electricity bill.

AVAILABLE

To participating Customers of owner occupied buildings where the primary source of heat is Electricity provided by the Company.

APPLICABLE

To Customers who have obtained an energy efficiency loan offered through programs managed by the Energy Trust of Oregon (Energy Trust) that include PGE's On Bill Repayment Service (EEAST loan).

SERVICE DESCRIPTION

Energy Trust of Oregon will offer financing to participating Customers and will act as a program coordinator. PGE will bill repayment of the EEAST loan offered by the Energy Trust on the participating Customer's Electricity bill. PGE will then remit the collected Customer repayments received to Energy Trust of Oregon or financial institution designated by the Energy Trust and communicated to PGE in writing.

Energy Trust of Oregon, through its contracted financial institution, is responsible to qualify Customers for the repayment service and establish a contract with the Customer for repaying the EEAST loan. Energy Trust of Oregon will obtain and provide to the Company, the participating Customer's written authorization that allows the repayment amount to be placed on the Customer's Electricity bill and for the Company to share the participating Customer's account payment and credit history with Energy Trust of Oregon as needed, on an ongoing basis.

SCHEDULE 340 (Continued)

SERVICE DESCRIPTION (Continued)

The On-Bill Repayment Service program is offered with the following understanding:

Related to the Participating Customer:

1. A Customer's participation in the On Bill Repayment Service will not affect the Customer's OAR Chapter 860, Division 21 rights and responsibilities or the Company's compliance with Division 21 rules. For example, the Company will not disconnect a Customer's service for non-payment of the EEAST loan repayment amount. The Customer's participation in the On Bill Repayment Service will not affect the Customer's ability to establish credit, impact the deposit amount the Customer may be required to pay, or otherwise affect the Customer's ability to receive reliable Electricity Service with the Company.

2. By securing an EEAST loan, the Customer will be responsible to remit the monthly EEAST loan repayment amount to PGE with the monthly bill payment for Electricity Service.

3. Customer payments remitted to the Company shall first be applied to those charges related to the provision of Electricity Service and other related services billed to the Customer consistent with the Company's tariff[1]. Overpayments received by the Company will not be applied to the EEAST loan balance, nor will refunds be issued. The overpayment will be applied towards Electricity Service charges in the same posting priority as defined within the Company's tariff[2].

4. Time Payment Agreements or other payment arrangements will not be available for the EEAST loan repayment amount, nor will Energy Assistance payments be applied to the EEAST loan repayment amount.

5. Delinquency Conditions: If a customer is seventy five (75) calendar days past due on their EEAST loan payment, the Company will notify the Energy Trust and no longer provide the On Bill Repayment Service to the customer if the EEAST loan remains past due. If the EEAST loan payment is more that ninety (90) calendar days past due, the Company will remove the Customer from the On Bill Repayment Service without notice to the Energy Trust or the Customer. A return check charge as provided in Schedule 300 will be applied to any payment returned by a financial institution.

1) Rule F, Billings, (5), Presentation and Payment of Bills
2) Should the overpayment be equal to that of the remaining EEAST Loan balance, the Company may issue a refund and advise the Customer to contact the Energy Trust on proper loan pay-off procedures.

SCHEDULE 340 (Continued)

SERVICE DESCRIPTION (Continued)

6. As the EEAST loan is specific to the Customer and the premises, if the Customer sells the property, the loan will revert to Energy Trust, and/or its financing organization. Energy Trust may work with the new owner to continue the repayment obligation; if the new owner is willing to continue the EEAST loan repayment obligation, the Energy Trust and PGE will treat this as a new EEAST loan.

Related to the Energy Trust of Oregon:

1. Energy Trust will reimburse Company for all costs related to Company's administration of this On Bill Repayment Service. The Company will bill Energy Trust for ongoing administrative costs, including costs associated with programming, credit searches, repayment set up, repayment termination, and other incremental activities related to processing bill payments, accounting and reporting. The Company will not seek to recover any incremental costs associated with this program from Customers. The business relationship between the Energy Trust and Company will be governed by an executed operating agreement.

2. The Company will transfer to the Energy Trust, on a monthly basis, a remittance that includes the aggregate amount of all EEAST loan repayment amounts received during the previous month, a listing of participating Customers, payment amounts and dates of payment and other information as agreed to between the Company and Energy Trust.

3. If any Customer payment transferred by the Company to Energy Trust or its designee is later reversed or payment declined because the Customer has insufficient funds with its bank or financial institution, the Company shall not be responsible for a return payment fee to the Energy Trust or its designee.

4. Upon receipt of written notice of a change in ownership of the premises of a participating Customer, the Company will not include repayment amounts on the Electricity bill for the new owner of the premises without first receiving written notification from Energy Trust of the following: a) a new qualifying Customer at the premises has established a contract for repayment of the payment obligation, b) written authorization from the new owner of the premises that allows the repayment amount to be placed on the new qualifying Customer's Electricity bill, and c) authorization for the Company to share the new qualifying Customer's account payment history and credit activity with the Energy Trust.

5. Dispute Resolution: Energy Trust must provide the Company with a toll-free Customer Service phone number to which the Company can refer Customers who have questions or concerns about their EEAST loan repayment obligation. The Company is not responsible for responding to Customer questions and disputes related to EEAST loan or for any misinformation provided by Energy Trust.

SCHEDULE 340 (Concluded)

SPECIAL CONDITIONS

1. PGE is acting as a billing agent for Energy Trust. By participating as billing agent, Customer agrees to hold the Company harmless from any cost, liability, claim, suit and expense arising out of any act or omission of Energy Trust, or its designee, its financing institutions, or contractors related to the installation of energy efficiency measures or upgrades, the effectiveness of such installations or resulting energy or financial savings, or any representations made directly or indirectly to Customer concerning energy usage, environmental impacts, property values or other effects or savings related to the energy efficiency measures. In addition, Customer agrees to hold the Company harmless from any action the Company may take in reliance on information provided to the Company by Energy Trust or associated financing institutions.

2. The service quality standards and requirements under the Oregon Administrative Rules for Customer Service shall not apply with respect to bills and remittances related to this EEAST On Bill Repayment service.

3. As a condition of participation in this Schedule 340 On Bill Repayment Service, participating customers must participate in the Company's auto pay program in which the Customer's electricity bill is automatically paid from the Customer's bank account. The Customer receives a monthly statement noting charges due, in advance of the due date, and the amount due is automatically withdrawn from the Customer's bank account when due. For more information, Customer is directed to http://www.portlandgeneral.com

TERM

This Schedule will be in effect until one of the following occurs: the Energy Trust /PGE operating agreement is terminated; all participating Customers have fully repaid their respective repayment obligations; or OPUC waiver, legislation, or judicial order terminates or materially changes the requirements of this Service.

SCHEDULE 341
ENERGY EFFICIENCY UPGRADE
VOLUNTARY ON-BILL REPAYMENT SERVICE

PURPOSE

This Schedule describes the general terms of the On-Bill Repayment Service that allows Customers, who have obtained energy efficiency upgrade financing offered through programs managed by the Energy Trust of Oregon, with repayment of the financed amount on the Customer's Electricity bill. This Service enables Customers access to low-cost, long-term financing provided by a third party financial institution for installed energy efficiency measures with the repayment amount included and separately stated on the participating Customer's Electricity bill as "Energy Upgrade Loan."

AVAILABLE

To Owners, who are the Customer of Record, of dwellings and/or buildings where Electricity is provided by the Company.

APPLICABLE

To Customers who have obtained an energy efficiency loan offered through programs managed by Energy Trust.

SERVICE DESCRIPTION

Energy Trust, will offer financing provided by a third party financial institution to participating Customers and will act as a program coordinator. PGE will bill repayment of the loan offered by the Energy Trust on the participating Customer's Electricity bill. PGE will then remit the collected Customer repayments received to Energy Trust or financial institution, designated by the Energy Trust, and communicated to PGE in writing.

Energy Trust through a third party with which Energy Trust contracts, is responsible to qualify Customers for the loan and repayment service and establish a contract with the Customer for repaying the loan. Energy Trust will obtain and provide to the Company, the participating Customer's written authorization that allows the repayment amount to be placed on the Customer's Electricity bill and for the Company to share the participating Customer's account payment and credit history with Energy Trust as needed, on an ongoing basis.

SCHEDULE 341 (Continued)

SERVICE DESCRIPTION (Continued)

The On-Bill Repayment Service program is offered with the following understanding:

Related to the Participating Customer:

1. A Customer's participation in the On-Bill Repayment Service will not affect the Customer's OAR Chapter 860, Division 21 rights and responsibilities or the Company's compliance with Division 21 rules. For example, the Company will not disconnect a Customer's service for non-payment of the loan repayment amount. The Customer's participation in the On-Bill Repayment Service will not affect the Customer's ability to establish credit with the Company, impact the deposit amount the Customer may be required to pay, or otherwise affect the Customer's ability to receive reliable Electricity Service provided by the Company.

2. By participating in this service, the Customer is responsible to remit the monthly loan repayment amount to PGE in addition to the monthly Electricity Service payment.

3. Customer payments remitted to the Company shall first be applied to those charges related to the provision of Electricity Service and other related services billed to the Customer consistent with the Company's tariff[1]. Overpayments received by the Company will not be applied to the loan balance, nor will refunds be issued. The overpayment will be applied toward Electricity Service charges in the same posting priority as defined within the Company's tariff[2].

4. Time Payment Agreements or other payment arrangements are not available for the repayment amount, nor will Energy Assistance payments be applied to the repayment amount.

5. Delinquency Conditions: If a customer is seventy-five (75) calendar days past-due on their loan payment, the Company will notify the Energy Trust through the third party with which Energy Trust contracts as their designated on-bill administer that the Company will no longer provide the On-Bill Repayment Service to the customer if the loan remains past due. If the loan payment is more that ninety (90) calendar days past due, the Company will remove the Customer from the On-Bill Repayment Service without notice to the Energy Trust or the Customer. A return check charge as provided in Schedule 300 will be applied to any payment returned by a financial institution.

6. As the loan is specific to the Customer and the premises, if the Customer sells the property, the loan will revert to Energy Trust, and/or the third party with which Energy Trust contracts. Energy Trust may work with the new owner to continue the repayment obligation; if the new owner is willing to continue the loan repayment obligation, the Energy Trust and PGE will treat this as a new loan.

1) Rule F, Billings, (5), Presentation and Payment of Bills
2) Should the overpayment be equal to that of the remaining Loan balance, the Company may advise the Customer to contact the Energy Trust on proper loan pay-off procedures.

SCHEDULE 341 (Continued)

SERVICE DESCRIPTION (Continued)

Related to the Energy Trust of Oregon:

1. Energy Trust will reimburse Company for all costs related to Company's administration of this On-Bill Repayment Service. The Company will bill Energy Trust for ongoing administrative costs, including costs associated with programming, credit searches, repayment set up, repayment termination, and other incremental activities related to processing bill payments, accounting and reporting. The Company will not seek to recover any incremental costs associated with this program from Customers. The business relationship between the Energy Trust and Company will be governed by the On-Bill Repayment Service Operating Agreement for non-EEAST Programs between Portland General Electric and the Energy Trust of Oregon.

2. The Company will, on a monthly basis, transfer to the Energy Trust or its designated third party on-bill repayment administrator, a remittance that includes the aggregate amount of loan repayments received during the previous month. The remittance will include a list of participating Customers, payment amounts, dates of payment, and other information as agreed by the Company and Energy Trust.

3. If any Customer payment transferred by the Company to Energy Trust or its designee is later reversed or payment declined because the Customer has insufficient funds with its bank or financial institution, the Company shall not be responsible for a return payment fee to the Energy Trust or its designee.

4. Upon receipt of written notice of a change in ownership of the premises of a participating Customer, the Company will not include repayment amounts on the Electricity bill for the new owner of the premises without first receiving written notification from Energy Trust of the following: a) a new qualifying Customer at the premises has established a contract for repayment of the payment obligation, b) written authorization from the new owner of the premises that allows the repayment amount to be placed on the new qualifying Customer's Electricity bill, and c) authorization for the Company to share the new qualifying Customer's account payment history and credit activity with the Energy Trust.

5. Dispute Resolution: Energy Trust must provide the Company with a toll-free Customer Service phone number to which the Company can refer Customers with questions or concerns. The Company is not responsible for responding to Customer questions and disputes related to the loan or for any misinformation provided by Energy Trust.

SCHEDULE 341 (Concluded)

SPECIAL CONDITIONS

1. PGE is acting as a billing agent for Energy Trust. By participating as billing agent, Customer agrees to hold the Company harmless from any cost, liability, claim, suit and expense arising out of any act or omission of Energy Trust, or its designee, its financing institutions, or contractors related to the installation of energy efficiency measures or upgrades, the effectiveness of such installations or resulting energy or financial savings, or any representations made directly or indirectly to Customer concerning energy usage, environmental impacts, property values or other effects or savings related to the energy efficiency measures. In addition, Customer agrees to hold the Company harmless from any action the Company may take in reliance on information provided to the Company by Energy Trust or associated financing institutions.

2. The service quality standards and requirements under the Oregon Administrative Rules for Customer Service shall not apply with respect to bills and remittances related to this On-Bill Repayment Service described herein.

3. As a condition of participation in this Schedule 341 On-Bill Repayment Service, participating Customers must participate in the Company's auto pay program in which the Customer's electricity bill is automatically paid from the Customer's bank account when due. The Customer receives a monthly statement noting charges due in advance of the due date and that amount automatically withdrawn from the Customer's bank account when due. For more information, Customer is directed to http://www.portlandgeneral.com

TERM

This Schedule will be in effect until one of the following occurs: the On-Bill Repayment Service Operating Agreement for the non-EEAST Programs between Portland General Electric and the Energy Trust of Oregon is terminated; all participating Customers have fully satisfied their respective loan obligations; or OPUC waiver, legislation, or judicial order terminates or materially changes the requirements of this Service.

SCHEDULE 402
PROMOTIONAL CONCESSIONS
RESIDENTIAL PRODUCTS AND SERVICES

PURPOSE

This schedule describes the Company's promotional concession program for enhancing the purchase of products and services.

APPLICABLE

To Residential Customers, qualified engineers, equipment vendors, installers, builders, contractors, and to commercial Customers for residential-type appliances, products, and services.

DESCRIPTION OF CONCESSION

From time to time, the Company will provide incentives to promote the purchase and installation of selected electrical appliances, products, and services. Incentives may include, but are not limited to, contests, discounts, rebates, gift certificates, free merchandise, etc.

In compliance with OAR 860-026-0025, the Company will submit a description of each concession to the Commission. In addition, the Company will furnish a copy of the description to any other energy utility providing service in any portion of the Company's service territory.

EXPIRATION / REVIEW DATE

This program will be offered as necessary to encourage installation of energy-efficient appliances and products, and support the introduction of new products and services.

ACCOUNTING TREATMENT

Project costs associated with selling and promoting Company products and services will be assigned to FERC Account 416.0 (Costs and Expenses of Merchandising). Other costs will be assigned to FERC Account 426.5 (Other Income Deductions).

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	$1,040.00	$920.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$3.18	$3.15
Over 200 kW	$3.08	$3.05
per kW of monthly On-Peak Demand	$1.56	$1.54
System Usage Charge		
per kWh	0.051 ¢	0.050 ¢

* 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 485 (Continued)

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.

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.

Wheeling Charge

The Wheeling Charge will be $1.964 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

SCHEDULE 485 (Continued)

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

CHANGE IN APPLICABILITY

If a Customer’s usage changes such that their facility capacity falls below 201 kW, the customer will be moved to an otherwise applicable rate schedule.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly On-Peak Demand (in kW) will be 100 kW for primary voltage service.

ON AND OFF PEAK HOURS

On-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

The following adjustment factors will be used where losses are to be included in the Energy Charges:

Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SCHEDULE 485 (Continued)

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a written service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the minimum Five-Year Option during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service under the minimum Five-Year Option subsequent to Enrollment Period* L must provide not less than three years notice to terminate service under this schedule. Such notices will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

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* A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 485 (Concluded)

SPECIAL CONDITIONS (Continued)

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers enrolled for service during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service subsequent to Enrollment Period* L must give the Company not less than three years notice to terminate service under this schedule. Such notices will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

* 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	$4,950.00	$4,900.00	$6,440.00
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.61	$1.59	$1.59
Over 4,000 kW	$1.30	$1.28	$1.28
per kW of monthly On-Peak Demand	$1.56	$1.54	$0.12
System Usage Charge			
per kWh	0.014 ¢	0.014 ¢	0.015 ¢

* 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 (Continued)

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.

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.

Wheeling Charge

The Wheeling Charge will be $1.964 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

SCHEDULE 489 (Continued)

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

ON AND OFF PEAK HOURS

On-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

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

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* A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 489 (Continued)

SPECIAL CONDITIONS (Continued)

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service under the minimum Five-Year Option subsequent to Enrollment Period* L must provide not less than three years notice to terminate service under this schedule. Such notices will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

SCHEDULE 489 (Concluded)

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers enrolled for service during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service subsequent to Enrollment Period* L must give the Company not less than three years notice to terminate service under this schedule. Such notices will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

* 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	$20,300.00	$20,300.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.75	$1.75
Over 4,000 kW	$1.44	$1.44
per kW of monthly on-peak Demand	$1.54	$0.12
System Usage Charge		
per kWh	0.007 ¢	0.005¢

* 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 (Continued)

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.

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.

Wheeling Charge

The Wheeling Charge will be $1.964 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

SCHEDULE 490 (Continued)

ON AND OFF PEAK HOURS

On-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

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

SCHEDULE 490 (Concluded)

SPECIAL CONDITIONS (Continued)

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer’s election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 491
STREET AND HIGHWAY LIGHTING
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment. 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

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE’s Customer Service or PGE’s Outdoor Lighting Services [1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE’s Outdoor Lighting Services at 503-736-5710, PGE’s Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 491 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs [(1)], in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. In addition, Maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to this Schedule.

SCHEDULE 491 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option B - Luminaire (continued):

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable.

Without obligation or notice to the Customer, following actual knowledge of an inoperable luminaire, the company will attempt to repair the photocell as soon as reasonably possible; if PGE does not possess the parts necessary for repair, PGE will replace inoperable luminaires with the equivalent LED luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services (1) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of certain failed parts including the lamp, power door (if applicable), photoelectric controller, starter and lens. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company's schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

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1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 491 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Option B Luminaire Maintenance (Continued)

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company.

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

3. The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given.

SCHEDULE 491 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

Option A provides for Company purchased and owned streetlight poles.

Pole Maintenance under Option A

Maintenance of Option A poles includes straightening of leaning poles, the replacement of rotted wood poles no longer structurally sound or any pole, which by definition, has reached its natural end of life at no additional charge to the customer. Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles.

Emergency Pole Replacement and Repair

The Company will repair or replace structurally unsound poles 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 and subject to the Company's operating schedules and requirements and at no additional charge to the Customer.

Option B - Poles

Option B provides for Customer purchased and owned streetlight poles. The Company does not, at any time, assume ownership of Option B streetlight poles.

Maintenance Service under Option B

The Company provides for maintenance only as defined herein to Customer purchased and owned poles and related equipment at the applicable monthly Option B rate and subject to the Company's operating schedules and requirements.

Maintenance of Option B poles includes straightening of leaning poles.

Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles, nor does maintenance of Option B poles include replacement of rotted wood poles no longer structurally sound, or any pole which by definition has reached its natural end of life.

Upon Customer request, the Company may install and replace Option B poles at their discretion that have reached their natural end of life. All costs associated to the installation and removal of any pole is the sole responsibility of the Customer, in addition to the applicable monthly Option B rate.

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	6.060 ¢ per kWh

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)

MARKET BASED PRICING OPTION (Continued)

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.

Wheeling Charge

The Wheeling Charge will be $1.964 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company’s Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

ON AND OFF PEAK HOURS

On-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

The following adjustment factors will be used where losses are to be included in the energy charges:

Secondary Delivery Voltage	1.0640

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$126.00 per hour	$161.00 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	*	$3.60	$2.61
	200	22,000	79	*	5.82	*
	400	50,000	163	*	10.93	9.88
Cobrahead, Non-Power Door	70	6,300	30	$7.98	3.11	1.82
	100	9,500	43	7.90	3.80	2.61
	150	16,000	62	*	4.96	3.76
	200	22,000	79	10.68	6.05	4.79
	250	29,000	102	11.61	7.39	6.18
	400	50,000	163	15.53	11.11	9.88
Flood	250	29,000	102	13.64	7.61	6.18
	400	50,000	163	17.34	11.31	9.88
Early American Post-Top	100	9,500	43	9.49	3.99	2.61
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	7.73	3.09	1.82
	100	9,500	43	*	3.95	2.61
	150	16,000	62	*	5.15	3.76

* 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	$5.52	$0.18
Fiberglass, Black or Bronze	30	8.98	0.30
Fiberglass, Gray	30	8.98	0.30
Fiberglass, Smooth, Black or Bronze	18	5.88	0.19
Fiberglass, Regular	18	4.97	0.16
Black, Bronze, or Gray	35	8.74	0.29
Aluminum, Regular with Breakaway Base	35	17.94	0.59
Aluminum, Smooth, Black, Pendant	23	18.31	0.60
Wood, Standard	30 to 35	6.70	0.22
Wood, Standard	40 to 55	7.87	0.26

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	$13.99	$4.51	$2.61
HADCO Victorian, HPS	150	16,000	62	15.15	5.67	3.76
	200	22,000	79	14.60	6.52	4.79
	250	29,000	102	15.91	7.90	6.18
HADCO Capitol Acorn, HPS	100	9,500	43	16.48	4.80	2.61
	150	16,000	62	*	5.90	3.76
	200	22,000	79	*	7.01	*
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	*	4.43	2.61
	150	16,000	62	*	*	3.76
HADCO Techtra, HPS	100	9,500	43	*	5.24	*
	150	16,000	62	22.68	6.49	3.76
	250	29,000	102	*	8.81	*
HADCO Westbrooke, HPS	70	6,300	30	14.83	3.88	*
	100	9,500	43	15.90	4.70	2.61

* 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	*	$6.19	*
	200	22,000	79	*	5.88	*
	250	29,000	102	$17.84	8.08	*
Special Types						
Flood, HPS	750	105,000	285	28.15	*	*
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	$3.88
Ornamental Acorn	55	2,800	21	*	*	1.27
Ornamental Acorn Twin	55	5,600	42	*	*	2.55
Composite, Twin	140	6,815	54	*	*	3.27
	175	9,815	66	*	*	4.00

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Regular	25	$9.49	$0.31
	30	10.87	0.36
	35	12.57	0.41
Aluminum Davit	25	10.12	0.33
	30	11.37	0.38
	35	12.99	0.43
	40	16.67	0.55
Aluminum Double Davit	30	12.61	0.42
Aluminum, Fluted Ornamental	14	8.95	0.30

* 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	Option B
Aluminum, Smooth Techtra Ornamental	18	$19.12	$0.63
Aluminum, Fluted Ornamental	16	9.29	0.31
Aluminum, Double-Arm, Smooth Ornamental	25	15.08	0.50
Aluminum, Fluted Westbrooke	18	17.98	0.59
Aluminum, Non-Fluted Ornamental, Pendant	18	17.87	0.59
Fiberglass, Fluted Ornamental Black	14	11.80	0.39
Fiberglass, Anchor Base, Gray or Black	35	11.89	0.39
Fiberglass, Anchor Base (Color may vary)	25	10.61	0.35
	30	12.94	0.43

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	*	*	$3.64
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.36
	175	7,000	66	$9.13	$5.18	4.00
	250	10,000	94	*	*	5.70
	400	21,000	147	14.26	10.13	8.91
	1,000	55,000	374	28.64	23.99	22.66
Holophane Mongoose,	150	16,000	62	*	5.75	*
HPS	250	29,000	102	*	8.20	*

* 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	$7.59	*	*
Mercury Vapor	175	7,000	66	9.75	$5.27	$4.00
Special box, Anodized Aluminum						
Similar to GardCo Hub HPS						
	70	6,300	30	*	*	1.82
	100	9,500	43	*	4.18	*
	150	16,000	62	*	*	3.76
	250	29,000	102	*	*	6.18
Metal Halide	250	20,500	99	*	7.04	6.00
	400	40,000	156	*	10.49	*
Cobrahead, Metal Halide	175	12,000	71	*	*	4.30
Flood, Metal Halide	400	40,000	156	15.34	*	9.45
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	4.79	3.76
KIM Archetype, HPS	250	29,000	102	*	8.22	6.18
	400	50,000	163	*	12.32	9.88

* 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	$10.30	$3.46	*
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	$1.82
Mercury Vapor	175	7,000	66	*	*	4.00
Early American Post-Top, HPS						
Black	70	6,300	30	6.78	2.99	1.82
Rectangle Type	200	22,000	79	*	*	4.79
Incandescent	92	1,000	31	*	*	1.88
	182	2,500	62	*	*	3.76
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	9.37	5.21	4.00
Flood, HPS	70	6,300	30	7.24	*	*
	100	9,500	43	7.79	3.80	*
	200	22,000	79	10.60	6.07	4.79
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	2.61
Twin ornamental, HPS	Twin 100	9,500	86	*	*	5.21
Compact Fluorescent	28	N/A	12	*	*	0.73

* 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	$5.06	*
Aluminum, Painted Ornamental	35	*	$0.43
Aluminum, Regular	16	5.12	0.17
Concrete, Ornamental	35 or less	9.38	0.31
Fiberglass, Direct Bury with Shroud	18	7.51	0.25
Steel, Painted Regular **	25	9.38	0.31
Steel, Painted Regular **	30	10.72	0.35
Steel, Unpainted 6-foot Mast Arm **	30	*	0.35
Steel, Unpainted 8-foot Mast Arm **	35	*	0.43
Wood, Laminated without Mast Arm	20	*	0.18
Wood, Curved Laminated	30	*	0.25
Wood, Painted Underground	35	6.63	0.22

* 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	*	*	$1.94
	165	12,000	60	*	*	3.64
	165	12,000	60	*	*	3.64

SCHEDULE 491 (Continued)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer’s selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

SCHEDULE 491 (Continued)

SPECIAL CONDITIONS (Continued)

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations.

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 491 (Continued)

SPECIAL CONDITIONS (Continued)

10. Indemnity:

a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer.

SCHEDULE 491 (Continued)

SPECIAL CONDITIONS (Continued)

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

SCHEDULE 491 (Continued)

SPECIAL CONDITIONS (Continued)

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

13. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

14. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

15. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

16. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

17. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

18. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

SCHEDULE 491 (Concluded)

SPECIAL CONDITIONS (Continued)

19. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. Where applicable, a Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

20. All lights corresponding to an individual municipal department must choose service under this schedule and/or Schedule 495.

21. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

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	1.674 ¢ per kWh

* 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 492 (Continued)

MARKET BASED PRICING OPTION (Continued)

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.

Wheeling Charge

The Wheeling Charge will be $1.964 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company’s Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

ON AND OFF PEAK HOURS

On-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

The following adjustment factors will be used where losses are to be included in the energy charges:

Secondary Delivery Voltage	1.0640

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 492 (Continued)

SPECIAL CONDITIONS

1. The Customer or ESS will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

2. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

3. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule using sampling techniques to determine, whether in the Company's opinion, the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Energy use as it may deem to be satisfactory or remove the Customer from service under this schedule.

4. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

5. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

6. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

7. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer’s election of service under this schedule.

8. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

SCHEDULE 492 (Concluded)

SPECIAL CONDITIONS (Continued)

9. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

10. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. Where applicable, a Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

11. All intersections corresponding to an individual municipal department must choose service under this schedule.

12. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 495
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment. 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

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE’s Customer Service or PGE’s Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE’s Outdoor Lighting Services at 503-736-5710, PGE’s Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 495 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option A (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs(1), in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services(2) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to this Schedule.
(2) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 495 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option B (Continued)

Maintenance under Option B luminaires specifically does not include replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

Emergency Luminaire Replacement and Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable

Without obligation or notice to the Customer, luminaire repair or replacement shall occur as soon as reasonably possible subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE’s Customer Service or PGE’s Outdoor Lighting Services(1) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of the photoelectric controller. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company’s schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

(1) Contact PGE’s Outdoor Lighting Services at 503-736-5710, PGE’s Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 495 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Option B Luminaire Maintenance (Continued)

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on non-Company owned poles or Company-owned distribution poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company.

Maintenance Service under Option C

The Company has no obligation to maintain Customer-purchased lighting if the Customer selects this option. Such maintenance and service is the sole responsibility of the Customer.

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

1. If Customer elects to convert any of its luminaires from Schedule 91/95 Option B to Schedule 95 Option C, the Customer must at the same time commit to convert the entirety of Customer's Schedule 91/95 Option B luminaires to Schedules 91 Option C and Schedule 95 Option C using one of two methods: (A) within five years following PGE's group lamp replacement cycle or (B) within three years on a schedule mutually agreed upon between the Company and Customer. Customer may elect to have some of its luminaires on Schedule 91 Option C and some on Schedule 95 Option C.

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.

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	6.060 ¢ per kWh

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)

MARKET BASED PRICING OPTION (Continued)

Wheeling Charge

The Wheeling Charge will be $1.964 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

ON AND OFF PEAK HOURS

On-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

The following adjustment factors will be used where losses are to be included in the energy charges:

Secondary Delivery Voltage	1.0640

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates (1)	Straight Time	Overtime
	$126.00 per hour	$161.00 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.

		Nominal	Monthly	Monthly Rates	
Type of Light	Watts	Lumens	kWh	Option A	Option B
Roadway LED	>20-25	3,000	8	$5.65	$0.90
	>25-30	3,470	9	5.72	0.97
	>30-35	2,530	11	6.21	1.10
	>35-40	4,245	13	5.96	1.21
	>40-45	5,020	15	6.26	1.34
	>45-50	3,162	16	6.36	1.40
	>50-55	3,757	18	6.76	1.52
	>55-60	4,845	20	6.56	1.64
	>60-65	4,700	21	6.62	1.70
	>65-70	5,050	23	7.46	1.83
	>70-75	7,640	25	7.61	1.96
	>75-80	8,935	26	7.67	2.02
	>80-85	9,582	28	7.79	2.14
	>85-90	10,230	30	7.91	2.26
	>90-95	9,928	32	8.03	2.38
	>95-100	11,719	33	8.09	2.44
	>100-110	7,444	36	8.49	2.63
	>110-120	12,340	39	8.45	2.80
	>120-130	13,270	43	8.70	3.05
	>130-140	14,200	46	9.83	3.25
	>140-150	15,250	50	11.42	3.52
	>150-160	16,300	53	11.60	3.70
	>160-170	17,300	56	11.78	3.88
	>170-180	18,300	60	11.94	4.13
	>180-190	19,850	63	12.21	4.31
	>190-200	21,400	67	12.32	4.55

SCHEDULE 495 (Continued)

RATES FOR STANDARD LIGHTING (Continued)

Light-Emitting Diode (LED) Only – Option C Energy Use

Type of Light	Watts*	Monthly kWh**
LED	5 - 10	3
LED	>10 - 15	4
LED	>15 - 20	6
LED	>20 - 25	8
LED	>25 - 30	9
LED	>30 - 35	11
LED	>35 - 40	13
LED	>40 - 45	15
LED	>45 - 50	16
LED	>50 - 55	18
LED	>55 - 60	20
LED	>60 - 65	21
LED	>65 - 70	23
LED	>70 - 75	25
LED	>75 - 80	26
LED	>80 - 85	28
LED	>85 - 90	30
LED	>90 - 95	32
LED	>95 - 100	33
LED	>100 - 110	36
LED	>110 - 120	39
LED	>120 - 130	43
LED	>130 - 140	46
LED	>140 - 150	50
LED	>150 - 160	53
LED	>160 - 170	56

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

SCHEDULE 495 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option C Energy Use (Continued)

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

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	Option B
Acorn					
LED	>35-40	3,262	13	$14.11	$1.38
	>40-45	3,500	15	14.23	1.50
	>45-50	5,488	16	11.74	1.51
	>50-55	4,000	18	14.41	1.68
	>55-60	4,213	20	14.53	1.80
	>60-65	4,273	21	14.59	1.86
	>65-70	4,332	23	14.32	1.97
	>70-75	4,897	25	14.84	2.11
HADCO LED	70	5,120	24	18.87	2.12
Pendant LED (Non-Flared)	36	3,369	12	15.81	1.35
	53	5,079	18	17.42	1.74
	69	6,661	24	17.52	2.09
	85	8,153	29	18.45	2.42
Pendant LED (Flared)	>35-40	3,369	13	15.46	1.41
	>40-45	3,797	15	15.58	1.53
	>45-50	4,438	16	15.64	1.59
	>50-55	5,079	18	18.58	1.76
	>55-60	5,475	20	18.70	1.88
	>60-65	6,068	21	18.76	1.94
	>65-70	6,661	23	17.97	2.04
	>70-75	7,034	25	18.10	2.17
	>75-80	7,594	26	18.39	2.24
	>80-85	8,153	28	18.51	2.36
Post-Top, American Revolution LED	>30-35	3,395	11	8.79	1.15
	>45-50	4,409	16	9.09	1.45
Flood LED	>80-85	10,530	28	9.07	2.17
	>120-130	16,932	43	10.53	3.09
	>180-190	23,797	63	12.97	4.32
	>370-380	48,020	127	21.36	8.30

SCHEDULE 495 (Continued)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer’s selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer’s request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

SCHEDULE 495 (Continued)

SPECIAL CONDITIONS (Continued)

6. For Option C lights: The Company does not provide the circuit on new installations.

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

10. Indemnification:

    a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

SCHEDULE 495 (Continued)

SPECIAL CONDITIONS (Continued)

b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

c. Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.c. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer.

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

SCHEDULE 495 (Continued)

SPECIAL CONDITIONS (Continued)

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

13. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

SCHEDULE 495 (Concluded)

SPECIAL CONDITIONS (Continued)

14. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

15. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

16. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

17. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

18. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

19. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. Where applicable, a Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

20. All lights corresponding to an individual municipal department must choose service under this schedule and/or Schedule 491.

21. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

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 6.060 ¢ per kWh

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire
Cobrahead				
Mercury Vapor	175	7,000	66	$9.05[2]
	400	21,000	147	14.18[2]
	1,000	55,000	374	28.56[2]
HPS	70	6,300	30	7.90[2]
	100	9,500	43	7.82
	150	16,000	62	9.05
	200	22,000	79	10.60
	250	29,000	102	11.52
	310	37,000	124	13.75[2]
	400	50,000	163	15.45

(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	$7.71(2)
	200	22,000	79	10.52(2)
	250	29,000	102	13.56
	400	50,000	163	17.26
Shoebox, HPS (bronze color, flat lens,	70	6,300	30	7.65
or drop lens, multi-volt)	100	9,500	43	9.04
	150	16,500	62	10.66
Special Acorn Type, HPS	100	9,500	43	13.91
HADCO Victorian, HPS	150	16,500	62	15.07
Early American Post-Top, HPS, Black	100	9,500	43	9.41
Special Types				
Cobrahead, Metal Halide	150	10,000	60	11.25
Cobrahead, Metal Halide	175	12,000	71	10.06
Flood, Metal Halide	350	30,000	139	17.06
Flood, Metal Halide	400	40,000	156	15.26
Flood, HPS	750	105,000	285	28.07
HADCO Independence, HPS	100	9,500	43	13.41
HADCO Techtra, HPS	100	9,500	43	20.59
	150	16,000	62	22.60

(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	$14.03
	>40-45	3,500	15	14.15
	>45-50	5,488	16	11.66
	>50-55	4,000	18	14.33
	>55-60	4,213	20	14.45
	>60-65	4,273	21	14.51
	>65-70	4,332	23	14.24
	>70-75	4,897	25	14.76
HADCO LED	70	5,120	24	18.79
Roadway LED	>20-25	3,000	8	5.57
	>25-30	3,470	9	5.64
	>30-35	2,530	11	6.13
	>35-40	4,245	13	5.88
	>40-45	5,020	15	6.18
	>45-50	3,162	16	6.28
	>50-55	3,757	18	6.68
	>55-60	4,845	20	6.48
	>60-65	4,700	21	6.54
	>65-70	5,050	23	7.38
	>70-75	7,640	25	7.53
	>75-80	8,935	26	7.59
	>80-85	9,582	28	7.71
	>85-90	10,230	30	7.83
	>90-95	9,928	32	7.95
	>95-100	11,719	33	8.01
	>100-110	7,444	36	8.41
	>110-120	12,340	39	8.37
	>120-130	13,270	43	8.62
	>130-140	14,200	46	9.75
	>140-150	15,250	50	11.33

(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)	>150-160	16,300	53	$11.51
	>160-170	17,300	56	11.69
	>170-180	18,300	60	11.86
	>180-190	19,850	63	12.12
	>190-200	21,400	67	12.24
Pendant LED (Non-Flare)	36	3,369	12	15.73
	53	5,079	18	17.34
	69	6,661	24	17.44
	85	8,153	29	18.37
Pendant LED (Flare)	>35-40	3,369	13	15.38
	>40-45	3,797	15	15.50
	>45-50	4,438	16	15.56
	>50-55	5,079	18	18.50
	>55-60	5,475	20	18.62
	>60-65	6,068	21	18.68
	>65-70	6,661	23	17.89
	>70-75	7,034	25	18.02
	>75-80	7,594	26	18.31
	>80-85	8,153	28	18.43
CREE XSP LED	>20-25	2,529	8	5.72
	>30-35	4,025	11	5.91
	>40-45	3,819	15	6.15
	>45-50	4,373	16	6.21
	>55-60	5,863	20	6.51
	>65-70	9,175	23	7.21
	>90-95	8,747	32	7.76
	130-140	18,700	46	10.05
Post-Top, American Revolution LED	>30-35	3,395	11	8.71
	>45-50	4,409	16	9.01
Flood LED	>80-85	10,530	28	8.99
	120-130	16,932	43	10.45
	180-190	23,797	63	12.89
	370-380	48,020	127	21.27

(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	$ 6.42
	40 to 55	7.59
Wood, Painted Underground	35 or less	6.36 (3)
Wood, Curved laminated	30 or less	7.51 (3)
Aluminum, Regular	16	4.91
	25	9.14
	30	10.52
	35	12.22
Aluminum, Fluted Ornamental	14	8.74
Aluminum, Fluted Ornamental	16	9.08
Aluminum Davit	25	9.77
	30	11.02
	35	12.64
	40	16.25
Aluminum Double Davit	30	12.26
Aluminum, Smooth Techtra Ornamental	18	18.77
Fiberglass Fluted Ornamental; Black	14	11.52
Fiberglass, Regular		
Black	20	5.31
Gray or Bronze	30	8.63
Black, Gray, or Bronze	35	8.46
Fiberglass, Anchor Base, Gray or Black	35	11.62
Fiberglass, Anchor Base (Color may vary)	25	10.26
	30	12.59
Fiberglass, Direct Bury with Shroud	18	7.17
Aluminum, Regular with Breakaway Base	35	17.60
Aluminum, Double-Arm, Smooth Ornamental	25	14.73
Aluminum, Smooth, Black, Pendant	23	17.96

(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 515 (Concluded)

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.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file to add the luminaire type to this rate schedule.

2. Maintenance of outdoor area lighting poles includes replacement of accidentally or deliberately damaged poles and luminaires. If damage occurs more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will pay for future installation or may mutually agree with the Company and pay to have the pole either completely removed or relocated.

3. If Company-owned area lighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned area lighting equipment or poles.

TERM

Service under this schedule will not be for less than one year.

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	$22.00
Three Phase	$31.00
Distribution Charge	
First 5,000 kWh	6.132 ¢ per kWh
Over 5,000 kWh	3.195 ¢ per kWh

* 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 532 (Concluded)

SPECIAL CONDITION

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.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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	$35.00	
Distribution Charge	7.858	¢ per kWh

* 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 538 (Concluded)

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

SPECIAL CONDITION

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 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**	$50.00
Winter Months**	No Charge
Distribution Charge	
First 50 kWh per kW of Demand	10.604 ¢ per kWh
Over 50 kWh per kW of Demand	8.604 ¢ per kWh

* 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 549 (Concluded)

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 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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

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

SPECIAL CONDITION

The Customer is also responsible for notification to the Company of any change in type of service provided to the Customer's premises.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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	$4,950.00	$4,900.00	$6,440.00
Distribution Charge			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.61	$1.59	$1.59
Over 4,000 kW	$1.30	$1.28	$1.28
per kW of monthly On-Peak Demand**	$1.56	$1.54	$0.12
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	0.014 ¢	0.014 ¢	0.015 ¢

* See Schedule 100 for applicable adjustments.
** 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.
*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 575 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand of the Large Nonresidential Customer when the Customer's generator is operating as planned by the Customer. Initially, the Customer's Baseline Demand will be the Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations. Subsequently, Customer may select its Baseline Demand in accordance with the applicable notice requirements set forth in this schedule adjusted for changes in load and planned generator operations. Planned generator operations include the Electricity planned to be produced by the generator as well as the Customer's plans to sell Electricity produced by the generator to the Company or third parties. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 576R, monthly Demand charges under Schedule 575 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

For the first three months of service under this schedule, the Facility Capacity will be equal to the Customer's Baseline Demand. Starting with the fourth month, the Facility Capacity will be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Period, but will not be less than the Customer's Baseline Demand.

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to the Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

SCHEDULE 575 (Continued)

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves, transition a Customer's load to Unscheduled Power. A Customer on Schedule 575 must take Spinning Reserves in all Billing Periods that their generator is expected to operate either provided by their ESS or the Company. Spinning Reserves are not required for Customers with Reserved Capacity of 2,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's Load Reduction Plan must be approved by the Company.

Self-Supplied Reserves

Customers with Nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

Supplemental Reserves Load Reduction Plan

In lieu of self supplying Supplemental Reserves through a self-supply agreement, a Customer may provide Supplemental Reserves through the submittal to the Company of a Load Reduction Plan that demonstrates the ability to reduce load within the first ten minutes of generator failure and specifies a kW amount of load reduction equal to 3.5% of the Reserved Capacity.

SCHEDULE 575 (Continued)

GENERATION CONTINGENCY RESERVES (Continued)
Supplemental Reserves Load Reduction Plan (Continued)

The Load Reduction Plan also will specify the notification processes for delivery of Supplemental Reserves, the requirements for Customer delivery of requested Supplemental Reserves, the requirements for Customer notification to Company of any changes in the ability to supply Supplemental Reserves, the settlement process to be used when Supplemental Reserves are supplied by the Customer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. The Customer Load Reduction Plan must be approved by the Company. If approved by the Company, and adhered to by the Customer, a credit to the Supplemental Reserves charges will be applied to Customer's bill based on the Supplemental Reserves Level as specified in the Load Reduction Plan.

If Customer fails to follow the Company-approved Load Reduction Plan, all Supplemental Reserves credits for the subsequent three months (Penalty Period) will be forfeited. If the Customer satisfactorily follows the Company-approved Load Reduction Plan during the Penalty Period, the Load Reduction Plan kW credit will be reinstated at the end of the three month Penalty Period.

If the Customer fails to follow the Company-approved Load Reduction Plan a second time during the Penalty Period and the following three months, the Load Reduction Plan will be terminated.

The duration of the Penalty Period will not be limited by the establishment of a new service agreement under this schedule.

Following termination or contract expiration, Customer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Customer is able to demonstrate the load reduction capability of the Plan to Company's satisfaction.

Notwithstanding the above, Customer may terminate the Company-approved Load Reduction Plan upon giving 6 month written notice to Company.

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 (Continued)

MINIMUM CHARGE

The Minimum Charge will be the Basic, Ancillary Services, Distribution, and Contingency Generation Reserves Charges, where applicable. In addition, the Company may require the Customer to specify a higher Minimum Charge, if necessary to justify the Company's investment in service facilities.

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the Actual Monthly Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written service agreement specifying the terms and conditions of service, the Customer’s Baseline Demand, the Customer’s Reserved Capacity, the Company’s and Customer’s contact information, and any other information necessary for implementation of service under this schedule. The term of the service agreement will be one calendar year (except that the term of the first service agreement will be the remainder of the year when signed plus the next calendar year) and will renew annually thereafter for successive one year terms, unless the Customer gives 90 days prior written notice. These terms and conditions will be consistent with this schedule.

2. Customers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Service Point (SP) and total Generator output.

3. Direct Access Service is available only upon acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the SP and total Generator output.

SCHEDULE 575 (Continued)

SPECIAL CONDITIONS (Continued)

4. If the Customer is served at Primary or Subtransmission Voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Period, the Customer or its ESS is billed for Ancillary Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8), Regulation and Frequency Response Service will be credited to the Ancillary Services Charge under this schedule. The credit will be the actual OATT charges incurred but will not to exceed the Monthly Demand for the Schedule 575 monthly Ancillary Services Demand multiplied by the applicable OATT (OATT Schedules 7 or 8) and such credit will not exceed the Ancillary Services Charge incurred under this schedule. No credit will be provided against any Energy Imbalance Service charges.

6. A Customer's failure to inform the Company of use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

7. The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the Customer's generating capacity.

8. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Company or Customer provides the following notice:

   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Company or Customer may make one such request per calendar year and will provide at least 6 months written notice;

   b) for a change in Baseline Demand that is greater than 5 MW, the Company or Customer must provide at least 13 months written notice with such change effective on January 1 of the applicable year. Any subsequent notice by the Company or Customer under this special condition must be made consistent with these notice requirements.

SCHEDULE 575 (Concluded)

SPECIAL CONDITIONS (Continued)

9. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council guidelines.

10. If the Customer is receiving service under this schedule and Schedule 576R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 576R Special Conditions.

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 On-Peak hours per day**	$0.061	$0.060	$0.005
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. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 576R (Continued)

ENERGY NEEDS FORECAST (ENF) AND ECONOMIC REPLACEMENT POWER (ERP)

Economic Replacement Power (ERP) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF). The ENF specifies the amount of Electricity in mWh for each hour that ERP is requested to serve some or all of the Customer’s load normally supplied by the Customer’s generation (amounts in excess of the Baseline Energy under Schedule 575). The Customer, or its agent, must provide the ENF to the Company a minimum of 90 minutes prior to the first hour that ERP is requested.

Each ENF will be based on the Customer’s expected energy requirements and the Customer will use best efforts to conform actual Energy usage to the ENF.

The ENF will specify the expected ERP needed by hour. The Customer, or its agent, will deliver the ENF to the Company in accordance with Company procedures. The Company can choose to allow delivery of all or a portion of the ENF and will inform Customer of any such adjustment to the submitted ENF. Customer acceptance of such modification of the ENF by the Company will be confirmed within 15 minutes of the proposed ENF revision by the Company. If the Company does not inform the Customer that it is modifying the submitted ENF within 30 minutes of receipt of the ENF, the ENF will be deemed accepted by the Company.

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer’s Schedule 575 Baseline Energy.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Customer is taking ERP less the sum of the Customer’s Schedule 575 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 Customer is taking ERP.

If the sum of the Customer’s Unscheduled and Schedule 575 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.

SCHEDULE 576R (Concluded)

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for any power cost adjustment for costs incurred while the Customer is taking Service under this schedule and 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 to the Customer pursuant to this schedule and agreement. All other Energy delivered will be made under the terms of Schedule 575. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. Customer is required to maintain Schedule 575 service unless otherwise agreed to by the Company.

3. All charges and requirements of Schedule 575 will apply except as provided for under this schedule.

4. ERP supplied will not be resold.

5. The Company may interrupt ERP due to Transmission constraints.

6. The Customer, or its agent, must notify the Company's Merchant Power Operations, at a specified phone number, as soon as practical of otherwise unplanned load deviations greater than 5 MW that are expected to last one hour or longer. The Company may require the Customer to change its forecast if the Company believes the forecast does not adequately represent the expected load.

7. Upon mutual agreement between the Company and Customer, the otherwise applicable Schedule 575 monthly Basic and Facility Capacity Charges will be replaced by a flat monthly Basic and Facility Capacity Charge billed under this schedule. The flat monthly Basic and Facility Capacity Charge will be set to maximize the economic value of sales under this schedule.

8. The Company is not responsible for providing market information to Customer.

9. The Company has no obligation to provide the Customer with ERP except as explicitly agreed to by both parties.

10. Each day of flow will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

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	$40.00
Three Phase Service	$50.00
Distribution Charges**	
The sum of the following:	
per kW of Facility Capacity	
First 30 kW	$5.70
Over 30 kW	$5.60
per kW of monthly On-Peak Demand	$1.56
System Usage Charge	
per kWh	0.844 ¢

* 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 583 (Continued)

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.

FACILITY CAPACITY

The Facility Capacity shall be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities.

REACTIVE DEMAND CHARGE

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.

NOVEMBER ELECTION WINDOW

Enrollment for 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 Enrollment Windows 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 583 (Concluded)

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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	$1,040.00	$920.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$3.18	$3.15
Over 200 kW	$3.08	$3.05
per kW of monthly On-Peak Demand	$1.56	$1.54
System Usage Charge		
per kWh	0.051 ¢	0.050 ¢

* 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 585 (Continued)

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.

FACILITY CAPACITY

The Facility Capacity shall be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly on-peak Demand (in kW) will be 100 kW for primary voltage service.

REACTIVE DEMAND CHARGE

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.

NOVEMBER ELECTION WINDOW

Enrollment for 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 Enrollment Windows 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 585 (Concluded)

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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	$4,950.00	$4,900.00	$6,440.00
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.61	$1.59	$1.59
Over 4,000 kW	$1.30	$1.28	$1.28
per kW of monthly on-peak Demand	$1.56	$1.54	$0.12
System Usage Charge			
per kWh	0.014 ¢	0.014 ¢	0.015 ¢

* 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 589 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (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.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

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.

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 589 (Concluded)

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

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	$20,300.00	$20,300.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.75	$1.75
Over 4,000 kW	$1.44	$1.44
per kW of monthly on-peak Demand	$1.54	$0.12
System Usage Charge		
per kWh	0.007 ¢	0.005 ¢

* 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 590 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (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.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

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.

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 590 (Concluded)

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 591
STREET AND HIGHWAY LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services [1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs (1), in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. In addition, Maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to this Schedule.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option B - Luminaire (continued):

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable.

Without obligation or notice to the Customer, following actual knowledge of an inoperable luminaire, the company will attempt to repair the photocell as soon as reasonably possible; if PGE does not possess the parts necessary for repair, PGE will replace inoperable luminaires with the equivalent LED luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services [(1)] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of certain failed parts including the lamp, power door (if applicable), photoelectric controller, starter and lens. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company's schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Option B Luminaire Maintenance (Continued)

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company.

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

3. The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given.

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

Option A provides for Company purchased and owned streetlight poles.

Pole Maintenance under Option A

Maintenance of Option A poles includes straightening of leaning poles, the replacement of rotted wood poles no longer structurally sound or any pole, which by definition, has reached its natural end of life at no additional charge to the customer. Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles

Emergency Pole Replacement and Repair

The Company will repair or replace structurally unsound poles 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 and subject to the Company's operating schedules and requirements and at no additional charge to the Customer.

Option B - Poles

Option B provides for Customer purchased and owned streetlight poles. The Company does not, at any time, assume ownership of Option B streetlight poles.

Maintenance Service under Option B

The Company provides for maintenance only as defined herein to Customer purchased and owned poles and related equipment at the applicable monthly Option B rate and subject to the Company’s operating schedules and requirements.

Maintenance of Option B poles includes straightening of leaning poles.

Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles, nor does maintenance of Option B poles include replacement of rotted wood poles no longer structurally sound, or any pole which by definition has reached its natural end of life.

Upon Customer request, the Company may install and replace Option B poles at their discretion that have reached their natural end of life. All costs associated to the installation and removal of any pole is the sole responsibility of the Customer, in addition to the applicable monthly Option B rate.

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	6.060 ¢ per kWh
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)
	$126.00 per hour	$161.00 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	*	$3.60	$2.61
	200	22,000	79	*	5.82	*
	400	50,000	163	*	10.93	9.88
Cobrahead, Non-Power Door	70	6.300	30	$7.98	3.11	1.82
	100	9,500	43	7.90	3.80	2.61
	150	16,000	62	*	4.96	3.76
	200	22,000	79	10.68	6.05	4.79
	250	29,000	102	11.61	7.39	6.18
	400	50,000	163	15.53	11.11	9.88
Flood	250	29,000	102	13.64	7.61	6.18
	400	50,000	163	17.34	11.31	9.88
Early American Post-Top	100	9,500	43	9.49	3.99	2.61
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	7.73	3.09	1.82
	100	9,500	43	*	3.95	2.61
	150	16,000	62	*	5.15	3.76

* 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	Monthly Rates Option B
Fiberglass, Black, Bronze or Gray	20	$5.52	$0.18
Fiberglass, Black or Bronze	30	8.98	0.30
Fiberglass, Gray	30	8.98	0.30
Fiberglass, Smooth, Black or Bronze	18	5.88	0.19
Fiberglass, Regular	18	4.97	0.16
Black, Bronze, or Gray	35	8.74	0.29
Aluminum, Regular with Breakaway Base	35	17.94	0.59
Aluminum, Smooth, Black, Pendant	23	18.31	0.60
Wood, Standard	30 to 35	6.70	0.22
Wood, Standard	40 to 55	7.87	0.26

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	$13.99	$4.51	$2.61
HADCO Victorian, HPS	150	16,000	62	15.15	5.67	3.76
	200	22,000	79	14.60	6.52	4.79
	250	29,000	102	15.91	7.90	6.18
HADCO Capitol Acorn, HPS	100	9,500	43	16.48	4.80	2.61
	150	16,000	62	*	5.90	3.76
	200	22,000	79	*	7.01	*
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	*	4.43	2.61
	150	16,000	62	*	*	3.76
HADCO Techtra, HPS	100	9,500	43	*	5.24	*
	150	16,000	62	22.68	6.49	3.76
	250	29,000	102	*	8.81	*
HADCO Westbrooke, HPS	70	6,300	30	14.83	3.88	*
	100	9,500	43	15.90	4.70	2.61

* 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	*	$6.19	*
	200	22,000	79	*	5.88	*
	250	29,000	102	$17.84	8.08	*
Special Types						
Flood, HPS	750	105,000	285	28.15	*	*
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	$3.88
Ornamental Acorn	55	2,800	21	*	*	1.27
Ornamental Acorn Twin	55	5,600	42	*	*	2.55
Composite, Twin	140	6,815	54	*	*	3.27
	175	9,815	66	*	*	4.00

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Regular	25	$9.49	$0.31
	30	10.87	0.36
	35	12.57	0.41
Aluminum Davit	25	10.12	0.33
	30	11.37	0.38
	35	12.99	0.43
	40	16.67	0.55
Aluminum Double Davit	30	12.61	0.42
Aluminum, Fluted Ornamental	14	8.95	0.30

* 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	$19.12	$0.63
Aluminum, Fluted Ornamental	16	9.29	0.31
Aluminum, Double-Arm, Smooth Ornamental	25	15.08	0.50
Aluminum, Fluted Westbrooke	18	17.98	0.59
Aluminum, Non-Fluted Ornamental, Pendant	18	17.87	0.59
Fiberglass, Fluted Ornamental Black	14	11.80	0.39
Fiberglass, Anchor Base, Gray or Black	35	11.89	0.39
Fiberglass, Anchor Base (Color may vary)	25	10.61	0.35
	30	12.94	0.43

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	*	*	$3.64
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.36
	175	7,000	66	$9.13	$5.18	4.00
	250	10,000	94	*	*	5.70
	400	21,000	147	14.26	10.13	8.91
	1,000	55,000	374	28.64	23.99	22.66
Holophane Mongoose, HPS	150	16,000	62	*	5.75	*
	250	29,000	102	*	8.20	*

* 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	$7.59	*	*
Mercury Vapor	175	7,000	66	9.75	$5.27	$4.00
Special box, Anodized Aluminum						
Similar to GardCo Hub						
HPS	70	6,300	30	*	*	1.82
	100	9,500	43	*	4.18	*
	150	16,000	62	*	*	3.76
	250	29,000	102	*	*	6.18
Metal Halide	250	20,500	99	*	7.04	6.00
	400	40,000	156	*	10.49	*
Cobrahead, Metal Halide	175	12,000	71	*	*	4.30
Flood, Metal Halide	400	40,000	156	15.34	*	9.45
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	4.79	3.76
KIM Archetype, HPS	250	29,000	102	*	8.22	6.18
	400	50,000	163	*	12.32	9.88

* 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	$10.30	$3.46	*
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	$1.82
Mercury Vapor	175	7,000	66	*	*	4.00
Early American Post-Top, HPS						
Black	70	6,300	30	6.78	2.99	1.82
Rectangle Type	200	22,000	79	*	*	4.79
Incandescent	92	1,000	31	*	*	1.88
	182	2,500	62	*	*	3.76
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	9.37	5.21	4.00
Flood, HPS	70	6,300	30	7.24	*	*
	100	9,500	43	7.79	3.80	*
	200	22,000	79	10.60	6.07	4.79
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	2.61
Twin ornamental, HPS	Twin 100	9,500	86	*	*	5.21
Compact Fluorescent	28	N/A	12	*	*	0.73

* 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	$5.06	*
Aluminum, Painted Ornamental	35	*	$0.43
Aluminum, Regular	16	5.12	0.17
Concrete, Ornamental	35 or less	9.38	0.31
Fiberglass, Direct Bury with Shroud	18	7.51	0.25
Steel, Painted Regular **	25	9.38	0.31
Steel, Painted Regular **	30	10.72	0.35
Steel, Unpainted 6-foot Mast Arm **	30	*	0.35
Steel, Unpainted 8-foot Mast Arm **	35	*	0.43
Wood, Laminated without Mast Arm	20	*	0.18
Wood, Curved Laminated	30	*	0.25
Wood, Painted Underground	35	6.63	0.22

* 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	*	*	$1.94
	165	12,000	60	*	*	3.64
	165	12,000	60	*	*	3.64

SCHEDULE 591 (Continued)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

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.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer’s selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

SCHEDULE 591 (Continued)

SPECIAL CONDITIONS (Continued)

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer’s request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations.

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A “Qualified Worker” means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a “qualified person” or “qualified employee” with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 591 (Continued)

SPECIAL CONDITIONS (Continued)

10. Indemnity:

a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer.

SCHEDULE 591 (Continued)

SPECIAL CONDITIONS (Continued)

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

SCHEDULE 591 (Concluded)

SPECIAL CONDITIONS (Continued)

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

TERM

Service under this schedule will not be for less than one year.

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	1.674 ¢ per kWh

* 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 592 (Concluded)

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

SPECIAL CONDITIONS

1. The Customer or ESS will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

2. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

3. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule using sampling techniques to determine, whether in the Company's opinion, the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Energy use as it may deem to be satisfactory or remove the Customer from service under this schedule.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 595
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[(1)] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 595 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option A (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs(1), in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services(2) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to this Schedule.
(2) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 595 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option B (Continued)

Maintenance under Option B luminaires specifically does not include replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

Emergency Luminaire Replacement and Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable.

Without obligation or notice to the Customer, luminaire repair or replacement shall occur as soon as reasonably possible subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE’s Customer Service or PGE’s Outdoor Lighting Services(1) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of the photoelectric controller. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company’s schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

(1) Contact PGE’s Outdoor Lighting Services at 503-736-5710, PGE’s Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 595 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Option B Luminaire Maintenance (Continued)

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on non-Company owned poles or Company-owned distribution poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. The Company may provide necessary circuits for an additional charge.

Maintenance Service under Option C

The Company has no obligation to maintain Customer-purchased lighting if the Customer selects this option. Such maintenance and service is the sole responsibility of the Customer.

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

1. If Customer elects to convert any of its luminaires from Schedule 91/95 Option B to Schedule 95 Option C, the Customer must at the same time commit to convert the entirety of Customer's Schedule 91/95 Option B luminaires to Schedules 91 Option C and Schedule 95 Option C using one of two methods: (A) within five years following PGE's group lamp replacement cycle or (B) within three years on a schedule mutually agreed upon between the Company and Customer. Customer may elect to have some of its luminaires on Schedule 91 Option C and some on Schedule 95 Option C.

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	6.060 ¢ per kWh
Energy Charge	Provided by Electricity Service Supplier

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$126.00 per hour	$161.00 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	$5.65	$0.90
	>25-30	3,470	9	5.72	0.97
	>30-35	2,530	11	6.21	1.10
	>35-40	4,245	13	5.96	1.21
	>40-45	5,020	15	6.26	1.34
	>45-50	3,162	16	6.36	1.40
	>50-55	3,757	18	6.76	1.52
	>55-60	4,845	20	6.56	1.64
	>60-65	4,700	21	6.62	1.70
	>65-70	5,050	23	7.46	1.83
	>70-75	7,640	25	7.61	1.96
	>75-80	8,935	26	7.67	2.02
	>80-85	9,582	28	7.79	2.14
	>85-90	10,230	30	7.91	2.26
	>90-95	9,928	32	8.03	2.38
	>95-100	11,719	33	8.09	2.44
	100-110	7,444	36	8.49	2.63
	110-120	12,340	39	8.45	2.80
	120-130	13,270	43	8.70	3.05
	130-140	14,200	46	9.83	3.25
	140-150	15,250	50	11.42	3.52
	150-160	16,300	53	11.60	3.70
	160-170	17,300	56	11.78	3.88
	170-180	18,300	60	11.94	4.13
	180-190	19,850	63	12.21	4.31
	190-200	21,400	67	12.32	4.55

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option C Energy Use (Continued)

Type of Light	Watts*	Monthly kWh**
LED	5 - 10	3
LED	>10 - 15	4
LED	>15 - 20	6
LED	>20 - 25	8
LED	>25 - 30	9
LED	>30 - 35	11
LED	>35 - 40	13
LED	>40 - 45	15
LED	>45 - 50	16
LED	>50 - 55	18
LED	>55 - 60	20
LED	>60 - 65	21
LED	>65 - 70	23
LED	>70 - 75	25
LED	>75 - 80	26
LED	>80 - 85	28
LED	>85 - 90	30
LED	>90 - 95	32
LED	>95 - 100	33
LED	>100 - 110	36
LED	>110 - 120	39
LED	>120 - 130	43
LED	>130 - 140	46
LED	>140 - 150	50
LED	>150 - 160	53
LED	>160 - 170	56

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option C Energy Use (Continued)

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

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	$14.11	$1.38
	>40-45	3,500	15	14.23	1.50
	>45-50	5,488	16	11.74	1.51
	>50-55	4,000	18	14.41	1.68
	>55-60	4,213	20	14.53	1.80
	>60-65	4,273	21	14.59	1.86
	>65-70	4,332	23	14.32	1.97
	>70-75	4,897	25	14.84	2.11
HADCO LED	70	5,120	24	18.87	2.12
Pendant LED (Non-Flared)	36	3,369	12	15.81	1.35
	53	5,079	18	17.42	1.74
	69	6,661	24	17.52	2.09
	85	8,153	29	18.45	2.42
Pendant LED (Flared)	>35-40	3,369	13	15.46	1.41
	>40-45	3,797	15	15.58	1.53
	>45-50	4,438	16	15.64	1.59
	>50-55	5,079	18	18.58	1.76
	>55-60	5,475	20	18.70	1.88
	>60-65	6,068	21	18.76	1.94
	>65-70	6,661	23	17.97	2.04
	>70-75	7,034	25	18.10	2.17
	>75-80	7,594	26	18.39	2.24
	>80-85	8,153	28	18.51	2.36
Post-Top, American Revolution					
LED	>30-35	3,395	11	8.79	1.15
	>45-50	4,409	16	9.09	1.45
Flood LED	>80-85	10,530	28	9.07	2.17
	>120-130	16,932	43	10.53	3.09
	>180-190	23,797	63	12.97	4.32
	>370-380	48,020	127	21.36	8.30

SCHEDULE 595 (Continued)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

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.

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

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

SCHEDULE 595 (Continued)

SPECIAL CONDITIONS (Continued)

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations.

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 595 (Continued)

SPECIAL CONDITIONS (Continued)

10. Indemnification:

    a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

    b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

    c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.c. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer.

SCHEDULE 595 (Continued)

SPECIAL CONDITIONS (Continued)

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

SCHEDULE 595 (Concluded)

SPECIAL CONDITIONS (Continued)

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 600
ELECTRICITY SERVICE SUPPLIER CHARGES

AVAILABLE

In all territory served by the Company.

APPLICABLE

To any Electricity Service Supplier (ESS), including an applicant ESS, providing service to Customers. To receive service under this schedule, the ESS must sign an ESS Service Agreement and abide by all provisions of the Company's Tariff.

SERVICES

The following services are offered to an ESS providing Electricity to one or more Direct Access Service Customers.

Transmission Services (Applicable to Scheduling ESS only)

Transmission services are provided to an ESS pursuant to the Company's Open Access Transmission Tariff (OATT), Original Volume No. 8 (PGE-8).

ESS Provided Regulation and Imbalance Service

An ESS that self-provides Regulation and Frequency Response and Energy Imbalance Services must provide the Company with a real-time load and power factor signal via electronic metering from the Customer load to the location designated by the Company, consistent with PGE's OATT and business practices.

SCHEDULE 600 (Continued)

ESS SUPPORT SERVICES

The following charges are applicable to Scheduling and Non-Scheduling ESSs:

(1)	Application Processing Fee	$400.00 with Application
(2)	Registration Renewal Fee	$200.00
(3)	Electronic Data Interchange Testing	$100.00 per man-hour for all hours in excess of 16 hours annually
(4)	Change of Effective Date Request (Rule K)	$35.00
(5)	Switching Fee (Rule K) (Applicable for each Enrollment or Drop DASR, not applicable for Rescind or Change DASRs)	$20.00
(6)	Customer Change of Location (Rule K)	$5,000.00

ESS BILLING SERVICES

(1)	ESS Consolidated Bill Billing Credit	$0.63 per bill
(2)	Late Pay Charge	2.2 % of delinquent balances for products and services purchased under this Tariff.

CUSTOMER INFORMATION

ESS Web Portal Historical Usage Download for Interval Data Charge	$20.00 per Service Point Identification (SPID)

BILLING AND PAYMENT

Charges incurred for Schedule 600 services are the responsibility of the ESS for which service was provided and are due and payable as described in the Company's General Rules and Regulations.

SCHEDULE 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company's OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE DISTRIBUTION LOSSES

The ESS will schedule sufficient Energy to provide for the following losses on the Company's distribution system:

		Delivery Voltage	
	Secondary	Primary	Subtransmission
Losses:	2.34%	1.25%	0.14%

SCHEDULE 689
NEW LARGE LOAD
COST-OF-SERVICE OPT-OUT
(>10 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer with new load requirements that are expected to constitute “New Large Load” as that term is defined below, and that has contractually opted out such New Large Load from PGE’s cost-of-service based pricing. Participation in this program means Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company.

New Large Load must be separately metered from an existing facility or measured separately with comparable accuracy in a mutually agreed upon form between the Customer and PGE, as specified within the opt-out agreement for this program. Any New Large Load being served under this Schedule 689 must meet a minimum load of 10 MWa over a consecutive 12-month period within the first 36 months of receiving service.

New Large Load is defined in OAR 860-038-0710 as: any load associated with a new facility, an existing facility, or an expansion of an existing facility which (1) has never been contracted for or committed to receiving electric service in writing by a cost-of-service Customer with the Company and (2) is expected to result in a 10 MWa or more increase in the Customer’s power requirements during the first three years after new operations begin.

Service under this rate schedule begins at the time that the new meter is energized, or at a mutually agreed upon date between the Customer and PGE. The Company and Customer will identify the SP(s) that qualifies for service under this rate schedule, which SP(s) will be referenced within the previously executed opt-out agreement between the Customer and the Company once the SP(s) is known. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. Construction meters and energy supplied during construction will not apply to this rate schedule.

Service under this schedule is limited to 119 MWa (hereafter referred to as the “cap”) and is available on a first-come, first-served basis to those who apply for service under this Schedule 689 and are deemed eligible; provided, however, that capacity must be available under the cap and such cap shall not be exceeded by those who are served under this Schedule 689. Likewise, the timing of service under this schedule may be impacted by the availability of existing transmission capacity on the system at the time service is requested and any planning requirements, consistent with the requirements of the Company’s Open Access Transmission Tariff.

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	$4,950.00	$4,900.00	$6,440.00
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.61	$1.59	$1.59
Over 4,000 kW	$1.30	$1.28	$1.28
per kW of monthly On-Peak Demand	$1.56	$1.54	$0.12
System Usage Charge			
per kWh	0.014 ¢	0.014 ¢	0.015 ¢
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.

SCHEDULE 689 (Continued)

ENERGY SUPPLY

The Customer may elect to purchase Energy from an Electric Service Supplier (ESS) certified by the PUC to do business in PGE's service territory,(Direct Access Service) or from the Company (Company Supplied Energy). Election of energy supply from an ESS or from the Company applies toward the cap of this program.

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 agreement between the Customer and the ESS.

Company Supplied Energy

The Company Daily Market 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.

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.

Additional charges to meet the state of Oregon's Renewable Portfolio Standard may apply following future Commission determination.

Wheeling Charge
The Wheeling Charge will be $1.964 per kW of monthly Demand.

RETURN TO COST OF SERVICE PRICING

Except when disenrolled for failure to meet the threshold load standard established in this schedule, Customers must provide not less than three years notice to terminate service under this schedule. If a Customer's return to cost-of-service increases rates for existing cost-of-service Customers by more than 0.5%, the Customer returning to cost-of-service will be subject to the forward looking rate adder, hereafter referred to as the "Energy Supply Return Charge" noted below, for three years beginning from the date of notice to return to cost-of-service.

Energy Supply Return Charge
$0.00 per kWh

SCHEDULE 689 (Continued)

TRANSMISSION CHARGE

Transmission and Ancillary Service charges will be as specified in the Company's OATT, as specified and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly On-Peak Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

ON AND OFF PEAK HOURS

On-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

The following adjustment factors will be used where losses are to be included in the Energy Charges:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

REACTIVE DEMAND CHARGE

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 applicable to this schedule are summarized in Schedule 100.

SCHEDULE 689 (Continued)

EXISTING LOAD SHORTAGE TRANSITION ADJUSTMENT

The Existing Load Shortage Transition Adjustment will be applied to the Existing Load Shortage of the Customer and to the Existing Load Shortage of the Customer's Affiliated Customers. An Affiliated Customer is a controlling interest which is held by another Customer, engaged in the same line of business as the holder of the controlling interest. Existing Load Shortage is the larger of zero or a Customer's average historic cost-of-service load plus Incremental Demand Side Management less the average cost-of-service eligible load during the previous 60 months. Average Historical Cost-of-Service Load is the average monthly Cost-of-Service Eligible Load during the preceding 60 months prior to signing of the service agreement between the Customer and the Company for service on this rate schedule. Incremental Demand Side Management is the effective net impact of energy efficiency measures after the Customer has entered a written and binding agreement with the Company through the service agreement between the Customer and the Company.

The Existing Load Shortage Transition Adjustment for the first 60 months is equal to 75 percent of fixed generation costs plus net variable power cost transition adjustments during the first 60 months after enrollment in this rate schedule. The Existing Load Shortage Transition Adjustment after 60 months of service on this rate schedule is equal to 100 percent of fixed generation costs plus net variable power cost transition adjustments.

The Customer may be exempted from the Existing Load Transition Adjustment if the Customer can demonstrate that the change in load in question is not due to load shifting activity described in OAR 860-038-0740. The Company will provide written notification to the Customer at least 30 days prior to charging the Existing Load Shortage Transition Adjustment. The Customer must demonstrate the change in load by providing a written request for exemption that includes explanation for the change in load and support from available documentation. The Company will approve or deny the request of the Customer within 90 days and will not charge the Existing Load Transition Adjustment within this time period.

ENROLLMENT

The prospective NLDA program participant with New Large Load and any current Large Nonresidential Customer with New Large Load, must notify the Company of its interest to enroll in this Schedule 689 and execute an opt out agreement at the earlier of one year prior to the expected energization date of the new meter or upon entering a written and binding service agreement for distribution service with the Company. The date of energization will be agreed upon between the Customer and the Company within a written and binding agreement for service under this Schedule, to be provided by the Company to the Customer. Upon energization, the Customer will begin service on PGE daily market energy option and will remain on daily market energy option unless and until PGE is notified that Customer has chosen an ESS and the ESS commences service.

SCHEDULE 689 (Continued)

ENROLLMENT (Continued)

Customer enrollment may be contingent upon additional agreements between the Company and the Customer, including but not limited to Minimum Load Agreements. The Company will not accept applications for service that exceed the current program cap or any remaining load available under the cap. Customer applications with expectations of load to grow beyond the program cap will require separate application and approval by the Commission.

A Customer will have ten (10) business days to sign the NLDA service agreement once tendered by PGE. If a Customer executes an opt out agreement for service under this schedule, and if a Customer is working with an ESS, the Company will notify the ESS when to send the enrollment Direct Access Service Request (DASR). Prerequisites and notification requirements are as contained in Rule K.

Applicants that do not meet the conditions above, or that are found in breach of the opt out agreement between the Customer and the Company are not eligible for enrollment/continued enrollment under this rate schedule. If the Customer or the Customer's selected ESS cannot demonstrate creditworthiness, the Customer will not be eligible for service under this rate schedule and will be enrolled in an applicable cost-of-service based rate.

Prior to receiving service, the existing or prospective Customer must agree to only purchase energy from a resource mix consistent with the specifications of OAR 860-038-0730(1), which does not include coal-fired generation. Prior to taking service under this program, the existing or prospective Customer must provide a signed affidavit to PGE representing that their energy supply will meet the requirements of OAR 860-038-0730 (1). Customers found in violation of the provision--that no coal will be delivered by wire after January 1, 2030--will be enrolled in the general cost-of-service opt out program in the next direct access opt out window and subject to transition adjustments as a new enrollment.

DE-ENROLLMENT

At the conclusion of 36 months of service, if Customer's actual load enrolled under this Schedule 689 does not meet the minimum load requirements for service under this rate schedule, the Company may de-enroll the Customer from this rate schedule. The Company will provide the Customer and the Commission with written notification of its decision prior to moving the Customer to the applicable cost-of-service rate schedule. The Customer may respond to the Company's notice in accordance with OAR 860-038-0750. A Customer that is de-enrolled will no longer be served by an ESS and will be served by the Company at an applicable cost-of-service rate. Once de-enrolled, the Customer is subject to all notice requirements and provisions of the applicable cost-of-service rate schedule under which the Customer is served. The Customer may elect to opt-out of cost-of-service in a subsequent direct access window, and in accordance with the Company's tariff requirements. Customers that opt out of cost of service in the September direct access window will be subject to Schedule 129 transition adjustment schedule charges.

SCHEDULE 689 (Continued)

DE-ENROLLMENT (Continued)

The Customer must provide written notification, within 60 days of PGE's notification of de-enrollment, to the Company and the Commission to demonstrate that its reduction in load to less than 10 MWa was the result of equipment failure, incremental demand side management, load curtailment or load control, or other causes outside the control of the Customer. The Customer must provide documentation to demonstrate this.

The Company will not transition a Customer to a new rate schedule before 90 days has passed since initial notification from the Company.

TERM

Service under this rate schedule will be for the minimum of 36 months to determine if the minimum load required for service under this rate schedule, 10 MWa for 12 consecutive months, is met. Upon completion of this term, if 10 MWa for 12 consecutive months is met, service will continue under this schedule. If the minimum load requirement is not met, the Customer will be de-enrolled and transitioned to the applicable cost-of-service rate and subject to all notice requirements and provisions of the applicable rate schedule under which the Customer is served.

QUEUE MANGEMENT PLAN

Pending an investigation of its NLDA tariff, PGE opened a non-binding queue to start the one-year notification period for any prospective NLDA program participant who wished to provide PGE with notice of its intent to participate in the New Load Direct Access program. In recognition of the program cap, the process for entry into the queue was posted on PGE's website, in advance of the opening of the queue, and prospective NLDA program participants were advised that queue positions would be established on a first-come, first-served basis, once the queue was opened. The purpose of the temporary queue process is to provide nondiscriminatory and transparent management of those interested in NLDA.

The opening of the queue and the start of the one-year notification period for all those who entered the queue on that date, was on April 15, 2019. Thus, any load energized prior to April 15, 2020 is deemed ineligible for NLDA.

PGE anticipates that once the program cap is reached or all prospective NLDA program participants who entered the queue on April 15, 2019 have been processed, whichever comes first, PGE will close its temporary queue. Thereafter, any prospective NLDA program participant will have their request for NLDA processed on a first-come, first-served basis, at any time any capacity is or may become available under the program cap, provided the Customer load fits within the available capacity under the cap. A new NLDA queue will be established if such should become necessary.

SCHEDULE 689 (Continued)

QUEUE MANGEMENT PLAN (Continued)

Once PGE tenders an opt out agreement under this schedule, the prospective NLDA program participant has ten (10) business days to sign and return the agreement to PGE, or the offer will be withdrawn.

Beyond the one-year notification period, a prospective NLDA program participant has up to one additional year to energize the new service (by April 15, 2021 for initial program participants) or two years if substation construction and/or substation upgrades are required to serve the Contracted Load (by April 15, 2022 for initial program participants), known as the “Timely Energization Date.” Temporary power will not be considered “energization” for the purposes of determining a program participant’s Timely Energization Date. Allowances will be made if delays in construction are outside of the NLDA program participant’s control, such as materiel delays, or delays caused by PGE. The Customer must notify PGE at least 30 days prior to the Timely Energization Date to qualify for an allowance for additional time. Failure to meet the Timely Energization Date will result in automatic disenrollment from the NLDA program and termination of the New Large Load Cost of Service Opt-Out Agreement.

PGE will calculate, in demand (kW), the New Large Load that is to be referenced in the New Large Load Cost of Service Opt-Out Agreement (“Contracted Load”) and used for the purposes of determining remaining capacity available under the program cap, if any. This calculation will generally be based on the capacity of service currently being requested by the prospective NLDA program participant. PGE will design and construct facilities to serve the Contracted Load stated in the NLDA contract.

Provided any capacity is available under the program cap, such capacity will be offered serially, to the next prospective NLDA program participant in the queue, provided such prospective NLDA program participant’s New Large Load can be served without exceeding the program cap. For example, if there is 25MWa available under the cap and the next prospective NLDA program participant in the queue with a 50MWa load seeks enrollment, that participant will be denied participation, as their New Large Load does not fit under the cap.

SPECIAL CONDITIONS

1. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar Customers not taking service under this schedule, including competitors to the Customer.

2. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer’s election of service under this schedule.

SCHEDULE 689 (Concluded)

SPECIAL CONDITIONS (Continued)

3. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it energy experts that assisted in making this decision.

4. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and arrangement and operation of such equipment will be subject to the approval of the Company.

5. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill.

6. Customers under this schedule are put on notice through Commission Order No. 20-002, that the Commission intends that all system participants including NLDA Customers, will be required to support resource adequacy. Should a change be justified in the future, it may be imposed on all NLDA Customers. Further, when the Commission considers any future proposed changes or requirements, the Commission stated that it intends to disfavor grandfathering.

7. Customers selecting service under this schedule are put on notice that PGE may be proposing changes to its curtailment schedules applicable to NLDA Customers, consistent with the invitation extended in Commission Order No. 20-002. If proposed, PGE would describe when and how NLDA Customers would be curtailed so that cost of service Customers are less likely to face cost shifts if and when any ESS supplying NLDA Customers fails to perform.

SCHEDULE 715
ELECTRICAL EQUIPMENT SERVICES

PURPOSE

To provide construction and maintenance to Customer or utility owned electrical equipment (other than equipment owned by the Company).

AVAILABLE

In the State of Oregon.

APPLICABLE

To all Nonresidential Customers and utilities.

CHARACTER OF SERVICE

The Company provides engineering, electrical design and construction, equipment maintenance and repair, preventative diagnostic and prevention maintenance, electrical oil containment and compliance with the Environmental Protection Agency's Spill Prevention Control and Countermeasure Oil Program (SPCC), equipment leasing, Energy recovery and revenue protection and electrical equipment refurbishing and disposal services.

BILLING RATES

Service will be contractually negotiated.

SPECIAL CONDITIONS

1. All fully distributed costs and revenues associated with the provision of Electrical Equipment Services will be charged or credited to non-utility accounts.

2. Electrical Equipment Services will be provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 806-038-0640.

3. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other electrical equipment services providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Electrical Equipment Services.

SCHEDULE 750
INFORMATIONAL ONLY: FRANCHISE FEE RATE RECOVERY

PURPOSE

To inform customers regarding the level of franchise fee rate recovery contained in each schedule's system usage or distribution charges.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory.

FRANCHISE FEE RATE RECOVERY

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate	Included in:
7	0.447 ¢ per kWh	Distribution Charge
15	0.750 ¢ per kWh	Distribution Charge
32	0.410 ¢ per kWh	Distribution Charge
38	0.422 ¢ per kWh	Distribution Charge
47	0.616 ¢ per kWh	Distribution Charge
49	0.511 ¢ per kWh	Distribution Charge
75		
Secondary	0.210 ¢ per kWh	System Usage Charge
Primary	0.208 ¢ per kWh	System Usage Charge
Subtransmission	0.205 ¢ per kWh	System Usage Charge
83	0.313 ¢ per kWh	System Usage Charge
85		
Secondary	0.255 ¢ per kWh	System Usage Charge
Primary	0.252 ¢ per kWh	System Usage Charge
89		
Secondary	0.210 ¢ per kWh	System Usage Charge
Primary	0.208 ¢ per kWh	System Usage Charge
Subtransmission	0.205 ¢ per kWh	System Usage Charge
90		
Primary	0.190 ¢ per kWh	System Usage Charge
Subtransmission	0.190 ¢ per kWh	System Usage Charge
91	0.851 ¢ per kWh	Distribution Charge
92	0.230 ¢ per kWh	Distribution Charge
95	0.851 ¢ per kWh	Distribution Charge

DO NOT BILL

SCHEDULE 750 (Concluded)

FRANCHISE FEE RATE RECOVERY (Continued)

The Rates, included in the applicable system usage and distribution charges are:

Schedule		Franchise Fee Rate		Included in:
485				
	Secondary	0.058	¢ per kWh	System Usage Charge
	Primary	0.058	¢ per kWh	System Usage Charge
489				
	Secondary	0.019	¢ per kWh	System Usage Charge
	Primary	0.019	¢ per kWh	System Usage Charge
	Subtransmission	0.019	¢ per kWh	System Usage Charge
490				
	Primary	0.011	¢ per kWh	System Usage Charge
	Subtransmission	0.011	¢ per kWh	System Usage Charge
491		0.681	¢ per kWh	Distribution Charge
492		0.043	¢ per kWh	Distribution Charge
495		0.681	¢ per kWh	Distribution Charge
515		0.580	¢ per kWh	Distribution Charge
532		0.199	¢ per kWh	Distribution Charge
538		0.215	¢ per kWh	Distribution Charge
549		0.268	¢ per kWh	Distribution Charge
575				
	Secondary	0.019	¢ per kWh	System Usage Charge
	Primary	0.019	¢ per kWh	System Usage Charge
	Subtransmission	0.019	¢ per kWh	System Usage Charge
583		0.105	¢ per kWh	System Usage Charge
585				
	Secondary	0.058	¢ per kWh	System Usage Charge
	Primary	0.058	¢ per kWh	System Usage Charge
589				
	Secondary	0.019	¢ per kWh	System Usage Charge
	Primary	0.019	¢ per kWh	System Usage Charge
	Subtransmission	0.019	¢ per kWh	System Usage Charge
590				
	Primary	0.011	¢ per kWh	System Usage Charge
	Subtransmission	0.011	¢ per kWh	System Usage Charge
591		0.681	¢ per kWh	Distribution Charge
592		0.043	¢ per kWh	Distribution Charge
595		0.681	¢ per kWh	Distribution Charge
689				
	Secondary	0.019	¢ per kWh	System Usage Charge
	Primary	0.019	¢ per kWh	System Usage Charge
	Subtransmission	0.019	¢ per kWh	System Usage Charge

DO NOT BILL

SCHEDULE 800
SERVICE MAPS

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers, third parties and Competitive Operations as defined in OAR 860-038-0005(8), but not to Company employees classified as "Merchant" according to FERC Standards of Conduct.

DESCRIPTION

The Company offers Public GIS data and maps at no cost through ArcGIS Online. This spatial data is not designed to help fulfill engineering, surveying or legal needs and is for informational purposes only. Direct requests to PGE's GIS Department for additional assistance or more detailed maps. Additional data or map requests are subject to the fees listed below.

ArcGIS Online data and maps are available for no cost at this URL: https://arcg.is/0fvGTL

PRICE LIST

GEOSPATIAL (GIS) PRODUCTS

Hardcopy Maps – by Quarter Section	Price	
11 X 17 Standard Format Map	$25.00(1)	
24 X 36 Large Format Map	$50.00	
Electronic Maps or Data Files by Quarter Section		
Static Plot file (.pdf)	$25.00(2)	
Active plot files (.dgn, .dwg)	$50.00(2)	
Google Earth Files (.kmz)	$50.00	
Geodata Files (.shp, .gdb)	$50.00	
Customized Hard Copy or Electronic Map or Data File		
Special Order (e.g., Boundary Map)	$150.00	One Hour Minimum
	$75.00	per hour for additional hours

MAP REQUESTS

Maps may be requested by calling PGE Customer Service at 503-228-6322 or contacting PGE's GIS department at GISDepartment@pgn.com

SCHEDULE 800 (Concluded)

PAYMENT

Payment is required at the time of ordering. Electronic maps or data files may be refreshed three times at no extra cost for up to one year after the initial purchase.

(1) The first 5 copies are free when new service is being installed at the site.
(2) One electronic copy is free when new service is being installed at the site.

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GENERAL RULES AND REGULATIONS

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RULE

RULE A
INTRODUCTION

1. **General**

These General Rules and Regulations provide the terms and conditions related to services offered by the Company under this Tariff.

2. **Territory Served**

The Company supplies Electricity Service in incorporated and unincorporated portions of Clackamas, Columbia, Hood River, Marion, Multnomah, Polk, Washington, and Yamhill counties, Oregon. The Company may also provide certain non-utility services in other parts of Oregon.

3. **Commission Rules, Regulations and Orders**

Existing and future lawful rules, regulations, and orders of the Commission will be considered a part of this Tariff.

4. **Tariff Compliance**

Service and rates are subject to all applicable General Rules and Regulations contained in the Tariff of which each schedule is a part.

5. **Relationship to Rate Schedules**

If a rate schedule provision conflicts with a provision in these General Rules and Regulations, the rate schedule provision will apply.

RULE B
DEFINITIONS

The terms listed below, which are used frequently in the Tariff, have the stated meanings:

Ancillary Services - Services necessary or incidental to the transmission and delivery of Electricity from resources to retail Electricity Customers, including but not limited to scheduling, frequency regulation, load shaping, load following, spinning reserves, supplemental reserves, reactive power, voltage control and energy balancing services.

Applicant - A person or business applying to the Company for Electricity Service or reapplying for service at a new or existing location after service has been discontinued.

Basic Charge - A monthly amount, specified in certain rate schedules, which is charged regardless of the amount of Energy consumed. The charge represents a part of the Company's fixed costs of making service available, such as meter reading and billing costs.

Billing Period - A time interval, which may vary between 27 and 34 days, between successive billing dates.

Commission - The Public Utility Commission of Oregon.

Company - Portland General Electric Company.

Customer - An individual, partnership, corporation, organization, government, governmental agency, political subdivision, municipality, or other entity who has applied for, been accepted, and is currently receiving Electricity Service at a Service Point (SP). A Customer who voluntarily terminates service and subsequently requests service with the Company at a new or existing location within 20 days after terminating service retains Customer status. For purposes of Schedule 201, a Customer may not be receiving Electricity Services from the Company.

Customer Service Agreement - An Agreement with a Customer that specifies Utility Provided Service or Direct Access Service terms and conditions for service under this Tariff.

Day of Flow - The day in which Electricity deliveries are made; measured as the time period beginning immediately after midnight for the hour ending 0100 and ending at exactly the end of the 2400 hour Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

Demand - The maximum rate of delivery of Electricity metered for purposes of billing, measured in whole kilowatts (kW) registered over a nominal 30-minute interval.

Demand Charge - A charge for registered Demand normally assessed to Customers with Demands greater than 30 kW.

RULE B (Continued)

Direct Access Service - The delivery by the Company of Electricity and applicable Ancillary Services by the Company that a Nonresidential Customer has purchased from an Electricity Service Supplier (ESS).

Direct Access Service Request (DASR) - Electronic notification provided by an ESS to the Company that a Customer has selected the notifying ESS as its supplier of Electricity Service. DASRs are also required for a Customer to terminate Direct Access Service and begin or resume receiving Electricity Service from the Company, rescind a previously submitted DASR, change the effective date of the enrollment DASR, or update the Customer's account information when the Customer is receiving Direct Access Service.

Electricity - Electric energy, measured in kilowatt-hours (kWh) or megawatt-hours (MWh); or electric capacity, measured in kilowatts (kW) or megawatts (MW), or both.

Electricity Schedule - A Scheduling ESS's projection of its hourly Electricity deliveries, measured in megawatt-hours (MWh) that are necessary to meet the aggregate hourly load of its Customers and the Customers of any Non-Scheduling ESS for which it provides scheduling service. The Electricity Schedule is for a Day of Flow and is provided to the Company in accordance with Western Electricity Coordinating Council (WECC) and National Energy Reliability Council (NERC) operating standards.

Electricity Service - The provision of Electricity to Customers by the Company or by an ESS using the Company's Facilities.

Electricity Service Supplier (ESS) - A provider of Electricity Service including a Large Nonresidential Customer that has obtained all necessary approvals to do business in the State of Oregon, is certified by the Commission if applicable, has met the Company's requirements for providing service and executed an ESS Service Agreement with the Company. The Company, when supplying Electricity to Nonresidential Customers in its own service territory, is not considered an ESS. The Company will classify ESSs as one of the following:

Scheduling ESS - An ESS that provides its own Electricity Schedule to the Company.

Non-Scheduling ESS - An ESS that does not provide the Company with a Schedule and relies on a Scheduling ESS for services related to scheduling and settlement.

Electric Vehicle - An electric vehicle is any vehicle propelled in whole or in part by electric energy stored on board for the purpose of propulsion, and where charging of the on-board electrical storage is provided in whole or in part, through a connection to the utility distribution system. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles (PHEV) and battery electric vehicles (BEV).

RULE B (Continued)

Energy - Electric energy commonly measured in kilowatt-hours (kWh) or megawatt-hours (MWh).

Energy Charge - A variable charge billed on the basis of a Customer's metered or estimated kilowatt-hours (kWh) usage.

Emergency Default Service - A service option provided by the Company to a Nonresidential Customer that requires Utility Provided Service with less than five business days' notice to the Company by the Customer or its ESS. This service is available to the Customer for a maximum of five consecutive days from initial purchase.

ESS Service Agreement - An agreement between the Company and an ESS specifying terms and conditions for service under this Tariff.

Facilities - Transmission and distribution plant and equipment owned and operated by the Company.

Facility Capacity - The Facility Capacity is the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

Farm Service - Nonresidential electric service furnished to Premises employed for the purpose of obtaining a profit in money by raising, harvesting, and selling crops; or by the feeding, breeding, management and sale of, or the producing of, livestock, poultry, fur-bearing animals, or honeybees; or for dairying and the sale of dairy products; or any other agricultural or horticultural use, animal husbandry, or any combination thereof. Farm Service includes the use of Energy to prepare and store the products raised on the Premises for human use and animal use and their disposal by marketing or otherwise. Farm Service does not include the use of Energy for commercial treatment, storage, or distribution of agricultural or horticultural products and does not include the use of land subject to the provisions of ORS Chapter 321 concerning commercial forestry.

Kilovar (kVAr) - A unit of reactive power equal to 1,000 reactive volt amperes.

Kilowatt (kW) - A unit of power equal to 1,000 watts.

Kilowatt-Hour (kWh) - The amount of Energy delivered in one hour when power is delivered at a constant rate of 1 kW.

Large Nonresidential Customer - A Nonresidential Customer whose monthly Demand has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service whose Demand has exceeded 30 kW.

RULE B (Continued)

Losses - The difference between the amount of electricity generated and the amount sold to Customers within a given period of time. Losses largely reflect the electricity lost as a result transformation and transmission, but also include Company use and potentially electricity theft.

Multi-Family Dwelling - A residential building that contains three or more dwelling units.

Network Meter - Metered service that is the basis of PGE's Smart Grid (Advanced Metering Infrastructure) Technology Program with functionality to collect, receive and transmit meter-related data remotely.

Nonresidential Customer - A Customer that does not meet the definition of a Residential Customer.

Non-Network Meter (Residential only) - Metered service not part of PGE's Smart Grid (Advanced Metering Infrastructure) Technology Program with functionality to collect and receive meter-related data for manual collection.

Operational Order to Deliver Electricity - An order issued by the Company to scheduling ESSs to deliver additional Electricity for purposes of maintaining the integrity of the Company's facilities.

Portfolio - A set of product and pricing options provided to Residential Customers and Small Nonresidential Customers.

Premises - Real and personal property owned and/or used by a Customer at a single location, which contains a Service Point.

Reactive Demand - The maximum rate of delivery of kilovolt-amperes reactive (kVars) measured over a nominal 30-minute interval. Reactive Demand must be supplied to most types of magnetic equipment, such as motors. It is supplied by generators or by electrostatic equipment, such as capacitors, motors or transformers. It is recognized as a necessary Ancillary Service.

Reactive Demand Charge - A charge for Reactive Demand assessed to Customers with loads that are supplied Reactive Demand on the Company's system.

RULE B (Continued)

Residential Customer - A Customer that has applied for and been accepted to receive service at a dwelling primarily used for residential purposes, including, but not limited to, single family dwellings, separately metered apartment units, mobile homes, and houseboats, but excluding dwellings employed for Transient Occupancy, such as hotels, motels, camps, lodges, and clubs. For purposes of this rule, a dwelling must contain permanent facilities for sleeping, bathing, and cooking.

Boarding houses with no more than four separate sleeping quarters for use by people who are not members of the Residential Customer's family and "adult foster homes" (defined in ORS 443.705 as a home or facility in which residential care is provided for five or fewer adults who are not related to the Residential Customer by blood or marriage) are residential dwellings.

When there is nonresidential use of Electricity at a dwelling used primarily for residential purposes, the Company will classify the Customer as residential if the Company determines that Electricity consumed in a typical month for residential use exceeds that consumed for nonresidential use, and if the nonresidential use is carried out primarily by the occupants of the dwelling.

Individual dwelling units in newly constructed multi-family residential buildings will be individually metered and billed as Residential Customers. Service through one meter to two dwelling units will be classified as one Residential Customer where an existing dwelling unit is or has been divided into two dwelling units, provided the ampacity of the service equipment is not increased. In the case where service is supplied through one meter to two or more new dwelling units, or to three or more existing dwelling units, service will be classified as nonresidential service.

With the exception of the separately metered Residential Electric Vehicle Time of Use (EV TOU) Option under Schedule 7, service through additional meters to other than dwellings on residential premises will be classified as nonresidential.

Scheduled Crew Hours - Those times that Company service crew personnel are working at their regular rate of pay. Scheduled Crew Hours may vary by location and type of work.

Service Point (SP) - Unless otherwise designated by agreement, the first point of connection of the Company's service drop, service lateral or bus to the Customer's service entrance conductors or equipment determined without regard to the location of the meter or metering equipment.

Service Point Identification (SPID) - A code that identifies each unique Service Point and associated Company meter location (if applicable).

Single-Family Dwelling - A residential building that contains less than three dwelling units.

RULE B (Continued)

Site

A. Buildings and related structures that are interconnected by facilities owned by a single retail electricity Customer and that are served through a single electric meter; or

B. A single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, such that
   1) Each building or structure included in the site is no more than 1,000 feet from at least one other building or structure in the site;
   2) Buildings and structures in the Site, and land containing and connecting buildings and structures in the Site, are owned by a single retail electricity Customer who is billed for electricity use at the buildings and structures; and
   3) Land will be considered to be contiguous even if there is an intervening public or railroad right of way, provided that rights of way land, on which municipal infrastructure facilities exist (such as streetlighting, sewerage transmission, and roadway controls), will not be considered contiguous.

Small Nonresidential Customer - A Nonresidential Customer who does not meet the definition of a Large Nonresidential Customer, which means the Nonresidential Customer has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service had not exceeded 30 kW.

Standard Service - A service option provided by the Company to a Nonresidential Customer who elects to purchase Electricity from the Company rather than from an ESS.

Summer Months - Summer Months are the six regular Billing Periods from May through October.

Tariff - This Tariff, including all schedules, rules and regulations as they may be modified or amended from time to time.

Theft of Service - Theft of Service occurs when an Applicant or Customer initiates or maintains Electricity Service through fraudulent means, including but not limited to providing false identification or false information to establish an account or credit, paying for Electricity Service with a stolen financial account, tampering with Company equipment including but not limited to the meter, or diverting service.

RULE B (Concluded)

Renewable Energy Certificates - Renewable Energy Certificates (RECs) consist of the non-power attributes resulting from the generation of Energy by a qualified renewable resource. Such attributes may be fuel, emissions, or other environmental characteristics deemed of value by a REC purchaser. Non-power attributes include, but are not limited to, any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and any other pollutant that is now or may in the future be regulated under the pollution control laws of the United States; and further include any avoided emissions of carbon dioxide (CO2) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate. These non-power attributes are expressed in MWh. Non-power attributes do not include any energy, reliability, scheduling, shaping or other power attributes.

Transient Occupancy - Tenancy at a Premise for a duration of less than 30 days.

Utility Provided Service - The provision of Electricity Service to a Customer by the Company.

Winter Months - Winter Months are the six regular Billing Periods from November through April.

RULE C
CONDITIONS GOVERNING CUSTOMER
ATTACHMENT TO FACILITIES

1. Acceptance of Electricity Service

By establishing or requesting a Service Point (SP) or by continuing an existing SP to the Company's Facilities, an owner or tenant of the property agrees to the following:

A. To be bound by the conditions of this Tariff including payment of costs for Electricity Service delivered at the rates and under the terms and conditions of this Tariff as in effect from time to time and all applicable Commission rules;
B. To pay any costs incurred by the Company to provide Electricity Service if Electricity is taken and there is no Customer; and
C. To have Electricity Service discontinued by the Company if there is no Customer.

2. Continuity of Electricity Service

A. **Generally**

Unless otherwise specified in a Customer Service Agreement, the Company intends to make Electricity Service available continuously at standard voltages on the Company's distribution system. The Company does not guarantee constant or uninterrupted delivery of Electricity, the constancy of its voltage or frequency, or against the loss or reversal of one or more phases in a three-phase service. The Company's obligation to provide or continue to provide Electricity Service is subject to the applicable provisions of this Tariff. During periods of imminent or actual system emergencies, the Company may curtail or interrupt service to the Customer in order to maintain system integrity.

B. **Short Term Emergency Curtailment**

During short term curtailment emergencies, the Company may find it 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 by initiating an Emergency Curtailment. A system emergency includes, but is not limited to, events caused by extreme weather, the temporary loss of a major generating plant or transmission facilities, or conditions that violate the North American Reliability Corporation (NERC) standards, or conditions that violate the operating requirements set forth by the Company's Reliability Coordinator. The Company will contact the Commission prior to an Emergency Curtailment unless circumstances deem prior notice impracticable. Upon the instigation of an Emergency Curtailment, the Company will begin complying with its Curtailment Operating Plan to restore system stability.

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 is 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.

RULE C (Continued)

D. **Company's Right to Remove Facilities**

The Company may remove its Facilities as specified in a Customer Service Agreement or when no longer used.

E. **No Customer**

The Company may refuse to maintain Facilities in place or to continue the availability of Electricity Service at any Premises for which the Company has No Customer.

3. Delivery Voltages

A. **Generally**

Electricity delivered under this Tariff is provided at alternating current, 60 hertz, single-or three-phase, at one of the following standard voltages:

B. **Secondary Voltages**

1) Generally
Single-phase, 120/240 volts, 3-wire, grounded
Single-phase, 240/480 volts, 3-wire, grounded
Three-phase, 208/120 volts, 4-wire, grounded wye
Three-phase, 240/120 volts, 4-wire, grounded delta
Three-phase, 480/277 volts, 4-wire, grounded wye
Three-phase, 480/240 volts, 4-wire, grounded delta
2) In Some Locations
Single-phase, 480 volts, 2-wire (no new service)
Single-phase, 120/208 volts, 3-wire
Three-phase, 240 volts, 3-wire (no new service)
Three-phase, 480 volts, 3-wire (no new service)

C. **Primary Voltages**

1) Generally
Three-phase, 12,470/7,200 volts, 4-wire, grounded
2) In Some Locations
Three-phase 34,500/19,918 volts, 4-wire grounded service
11,400/6,660 volts, 4-wire, grounded service and 11,100/6,480 volts, 4-wire grounded service
(New installations will not be supplied at 2,400 or 4,160/2,400 volts.)

RULE C (Continued)

D. **Subtransmission Voltage**

At 59.8-kV, voltage range is: 57.62-kV to 63.68-kV
At 115-kV, voltage range is: 112.10-kV to 123.90-kV

E. **Selection of Voltage Furnished**

The voltage to be furnished is at the Company's option and will depend upon the characteristics of the Company's distribution system near the SP, the applicable rate schedule and the Customer's service requirements.

4. Conditions for Receiving Service

A. **Generally**

This section describes the physical and technical requirements necessary to interconnect the Company's Facilities with the SP.

B. **Rights-of-Way and Access**

The Customer must provide, without cost to the Company, all rights-of-way and easements on the Premises to be served for the construction, maintenance, repair, replacement, or use of any or all Facilities necessary or convenient for the supply of Electricity. The Customer must grant the Company free and unrestricted access to the Premises at all reasonable times for purposes of reading meters, trimming trees, and inspecting, testing, repairing, removing or replacing any or all Facilities of the Company.

C. **Customer-Supplied Equipment**

1) Customer's Responsibility
The Customer will, at the Customer's risk and expense, furnish, install, inspect, and maintain in a safe condition all wiring, equipment, apparatus, protective devices, raceways, and enclosures which may be required beyond the SP for receiving and using Electricity. The Company may, at its option, install and maintain Facilities beyond the SP where deemed necessary to provide adequate Electricity Service. For service(s) that relate to Transportation Electrification (TE) and Electric Vehicle (EV), the Company may install and operate assets beyond the SP in order to facilitate the expansion of TE across the Company's service territory.

RULE C (Continued)

Customer-Supplied Equipment (Continued)

2) Conformance with Codes
Before the Company will provide Electricity Service, the Customer's wiring and equipment must conform to applicable municipal, county and state requirements, and to accepted standards of the National Electrical Safety Code, the National Electric Code, the Company's published "Electric Service Requirements and Guidelines," and Company standards and practices. As required by law, the Customer or its agent must obtain a certificate of electrical inspection before the Company will provide Electricity Service.
3) Company's Right to Inspect
The Company has the right, but is not obligated, to inspect any Customer-owned installation, including all wiring, conduit, meter-bases or supporting equipment up to the electric meter and/or SP, at any reasonable time.
4) Effect of Customer's Load
The Customer must reasonably balance load between phases of a three-phase service or between ungrounded conductors of a single-phase, three-wire service. The Customer’s equipment must not cause excessive voltage fluctuations on the Company's lines. The Company has the right to refuse, discontinue or to regulate hours of Electricity Service to loads that could, in the Company's opinion, impair Electricity Service to other Customers.
5) Notice of Changes in Customer Load
A Customer must give the Company prior written notice before making any material change in either the amount or character of the Customer’s electrical appliances, apparatus or equipment, thereby allowing the Company to ascertain whether any changes are needed in its Facilities and to make such alterations in the charges for Electricity Service as may be required by this Tariff for the changed installation. If damage results to Facilities owned by the Company through failure of the Customer to notify the Company, the repair and, or replacement costs of such Facilities will be paid by the Customer.
6) Trouble Calls
When the Company, in responding to a report of an outage or other continuity of Electricity Service problem, determines the cause of the service problem to be solely in the Customer's equipment, the Company will bill the Customer for charges as listed under Schedule 300.
7) Miscellaneous Equipment Rental
When available, the Customer may elect to rent equipment from the Company including, but not limited to, transformers, single-phase to three-phase inverters, capacitors, and other related equipment in accordance with charges specified under Schedule 300 and the terms and conditions of the equipment rental agreement.

RULE C (Continued)

D. **Hazardous Substances**

1) Evaluation of Job Sites
The Company reserves the right, but is not obligated, to evaluate the job site of any new line extension request or of any required maintenance or repairs of existing Facilities for the purpose of identifying any hazardous wastes, hazardous substances or contaminants ("hazards") in soils or surface at the job site, as such hazards are defined under state or federal law.

2) Information About Hazards
Information about hazards may include the following:
   a) The job site is within an area designated or listed as a hazardous site by a state or federal environmental agency; or
   b) The Customer, Applicant or an employee of the Company or agent of the Company, Customer or Applicant reports unusual or inappropriate odor, color or material in, or adverse physical reaction to, soil or surfaces at the job site.

3) Treatment of Information About Hazards
If the Company receives information that hazards may exist at a job site, and such hazards may, in the Company's determination based upon applicable state, federal and industry standards, cause a risk to the health or safety of its employees or agents or the viability of equipment in the installation, maintenance, or repair of service, the Company will specify mandatory conditions for the protection of its employees, agents, or equipment. The Company also may require that the Customer or Applicant indemnify the Company against future claims related to the existence of the hazard. The cost of complying with the Company's conditions and with following state and federal regulations for the handling of the hazard, including, but not limited to, the cost of testing, handling, transporting and disposing of contaminated soil will be borne by the Customer or Applicant.

4) Remediation of Hazardous Conditions
The Company may require the Customer or Applicant to bear the cost of remediation or relocation of Company Facilities, if conditions cannot be prescribed which, in the Company's judgment, will adequately protect its employees or agents against hazards.

5) Remediation Costs
Nothing contained in this Tariff will be construed as obligating the Company to pay any remediation costs relating to hazards.

6) Hazards in Public Right-of-Way
This Tariff does not apply to hazards in a public right-of-way, either for purpose of recovery of extraordinary costs associated with installation, maintenance or repair, or for indemnification against future costs, except where the Customer’s or Applicant’s Premises are the source of the hazards in the right-of-way.

RULE C (Continued)

5. Interconnection of Customer-Generator Facilities

The following will apply to all interconnected Customers unless they are covered by an Interconnection Agreement entered into pursuant to the Company's Open Access Transmission Tariff (OATT) on file with the Federal Energy Regulatory Commission (FERC).

A. **Conformance with Regulations**

In order to ensure system safety and reliability of interconnected operations, the facility will be constructed, interconnected, and operated in accordance with all applicable federal, state, local laws and regulations, including the Company's Interconnection Guidelines, as may be amended from time to time.

B. **Control and Protective Devices**

The Customer will furnish, install, operate, and maintain in good order and repair without cost to the Company such switching equipment, relays, locks and seals, breakers, automatic synchronizers, and other control and protective apparatus as shown by the Company to be reasonably necessary for the operation of the facility in parallel with the Company's system. In all cases, the protective relaying design and equipment proposed for the interconnection of generator(s) must be approved by the Company.

C. **Cost Responsibilities**

The Customer is responsible for all costs of interconnection including any costs incurred by the Company. Additionally, the Customer is responsible for any modification to the Customer's facility that may be required by the Company for purposes of safety and reliability. The Customer will also reimburse the Company for administrative costs the Company incurs in this process.

D. **Conformance with Codes**

A facility will meet all applicable safety and performance standards established in the Oregon State Building Code. The standards will be consistent with the applicable standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories or other similarly accredited laboratory.

RULE C (Continued)

E. **Isolating Equipment**

A readily accessible, lockable and visible-break isolation device will be provided by the Customer at the point of interconnection for the Company's use and will be accessible to the Company at all times. At the Company's option, the Company may operate the isolating equipment if, in the sole opinion of the Company, continued operation of the qualifying facility in connection with the Company's system may create or contribute to a system emergency. At the Company's option, Customers installing small photovoltaic generators may customize their isolating equipment.

6. Transformers

A. **Generally**

Transformers furnished by the Company will be sized to the Customer's kVA requirement as determined by the Company. Transformers furnished by the Customer must be approved by the Company prior to connection.

B. **Restrictions on Transformer Types**

The Company will not furnish transformers with unusual specifications or connections, transformers with voltages not provided by the Company, or transformers insulated with gases or fluids other than oil. Dry-type transformers will be furnished only if:

1) A dry-type transformer installed by the Company prior to October 1, 1975, fails while in service.
2) A Company-owned, dry-type transformer requires replacement because of overload, provided no increase in the ampacity of the Customer's service entrance equipment has been made.
3) Multiple transformations are required to provide 120/240-volt single-phase service to load centers located throughout a residential building over five stories where the tenants are directly metered.

7. Relocation or Removal of Facilities

A. **Generally**

Any relocation of Facilities for a requesting party, including builders, developers, Customers or Customers' agents, will be performed by the Company at the requesting party's expense. The Company may require payment in advance of a sum equal to the estimated original cost of installed Facilities to be removed, less estimated salvage and less depreciation, plus estimated removal cost, plus any operating expense associated with the removal or relocation.

RULE C (Continued)

B. **Public Works Project**

Under the following circumstances, the cost for relocation or removal of Facilities within the public right-of-way will be borne by the Company unless an ordinance, legislation or private agreement specifies other cost responsibilities:

1) The rearrangement can be identified to be for a Public Works Project. Examples of Public Works Projects include but are not limited to public transit or a road widening financed by public funds;
2) Reasonable notice is provided to the Company;
3) The overall project can generally be scheduled during normal work hours (excluding load transfers which may need to be performed outside of normal work hours); and
4) The Public Works Project does not require the Company to make temporary relocations.

C. **Easement**

Costs for permanently relocating Facilities on a private easement will be borne by the requesting party regardless of status as Public Works Project or otherwise.

D. **Permit Job**

Where it can be identified that the requesting party has received a permit through a city or county for work within the public right-of-way that is required for the requesting party's construction project, the requesting party is responsible for all of the costs associated with the necessary rearrangement of Facilities.

E. **Relocation of Overhead or Underground Facilities at Company Expense**

If the necessary work can be performed by Company crews in a single trip to the requesting party's Premises during Scheduled Crew Hours (7:00 a.m. to 3:30 p.m., Monday through Friday, except Company recognized holidays) relocation or removal of overhead or underground service distribution Facilities on or adjacent to the Premises will be performed at Company expense, under the circumstances listed below. For underground relocations, the requesting party is responsible for any necessary trenching, boring, backfilling, conduit, paving, vaults and pads.

1) Such Facilities are idle, meaning not receiving Electricity Service for more than six months, except in the case of conversion from overhead to underground service; or
2) The location of such Facilities in the street area deprive the requesting party of reasonable ingress to or egress from the Premises, provided such Facilities are not on a property line or a property line extended. Generally, one driveway is considered reasonable ingress or egress; or

RULE C (Continued)

Relocation of Overhead or Underground Facilities at Company Expense (Continued)

3) Such Facilities occupy space on the requesting party's Premises that will be used for an expansion of the requesting party's building or plant. In these cases, the Line Extension Allowance will apply for the expansion. Costs exceeding the Line Extension Allowance must be borne by the Customer; or
4) The purpose is to relocate a meter to a more accessible location approved by the Company; or
5) Relocation of a service drop is the only work requested.
If more than one trip is required to accommodate the Customer, the Customer will be billed all costs plus loadings incurred for the additional trips.

F. **Temporary Relocations**

Where the Company is required to temporarily move its Facilities either because the Company cannot move its Facilities to the new permanent placement or the Facilities will be returned to their former location at a later point in time, the costs of the temporary relocation will be borne by the requesting party regardless of its status as a Public Works Project or otherwise. A temporary relocation is defined as any relocation where the Company must move its facilities two or more times within a three-year period.

8. Service Restoration

A. **Generally**

During a major outage due to events such as a major storm, the Company will follow priorities for service restoration as provided below. These restoration procedures are followed in order to restore service to the greatest number of Customers as quickly, efficiently, and safely as possible with special consideration given to Customers that are critically essential to public safety and welfare.
The Company maintains a list of critical Customers that includes but is not limited to hospitals, airports, 911 dispatch centers, fire and police stations, water and sewage treatment plants, emergency media, and emergency communications facilities. The Company will establish a prioritization framework for service restoration to critical Customers that leverages the service priority order in the next section.

B. **Service Priority [Order]**

The Service restoration work priorities listed below may be performed in parallel by different work crews from different parts of the Company to ensure all Customers are restored as quickly, efficiently, and safely as possible.
The priorities for service restoration are generally as follows:

RULE C (Concluded)

Service Priority [Order] (Continued)

1) Protect Public Safety
   The Company will clear energized, downed power lines and repair equipment that poses a public safety hazard. The Company will ensure that critical [Customers'] facilities have power.
2) Check Generation Facilities
   The Company will determine if repairs are needed to any of its generation facilities. If so, the generation facility will be taken off-line, and the Company will use undamaged generation facilities for power production.
3) Repair Transmission Lines to Substations. The Company will make necessary repairs to the transmission system, connecting generation facilities to substations to ensure system stability. The Company will also make necessary repairs to transmission lines, substations, and distribution facilities prioritizing those that connect substations to critical Customers. The Company will continue to repair remaining transmission lines.
4) Repair Substations
   The Company will repair substations making it possible to restore service to distribution lines.
5) Repair Feeder Distribution Lines
   The Company will repair distribution lines serving critical Customers as well as lines that may be blocking streets or highways. The Company will repair remaining distribution lines after service is restored to critical Customers.
6) Repair Tap Lines
   The Company will repair tap lines that serve smaller groupings, such as Residential Customers.
7) Repair Individual Service Connections
   The Company generally will repair individual service connections last. If Customer-owned equipment has been damaged, such as the meter base, that equipment must be repaired to the satisfaction of the authority having jurisdiction, including obtaining any required permits and inspections, before the Company can restore service at that location. Such repairs are the responsibility of the Customer.

C. **Other**

The Company will not give priority restoration to any Customer, non-utility generator or ESS, but will employ the above process over the Company's entire territory served.

RULE D
APPLICATION FOR ELECTRICITY SERVICE

1. Notification Requirement

An Applicant must provide the Company with five business days notice of intent to purchase Utility Provided Service.

2. Required Residential Identification Standards

In order to establish Electricity Service, an Applicant must provide identification as outlined below as well as meet the credit requirements as established in Rule E.

A. **Residential Applicants**

1) A Residential Applicant must provide the following information for the person(s) responsible for payment of the account:
   a) Name(s);
   b) Name to be used to identify the account, if different than the actual name(s) provided under (1)(a);
   c) Date(s) of birth;
   d) One of the following:
      i. Social Security Number(s) (SSN);
      ii. an Individual Taxpayer Identification Number (ITIN) issued by the Internal Revenue Service (IRS),
      iii. current, valid Driver's License Number(s)
      iv. other current, valid state or United States Federal identification containing the name and photograph of the person(s) responsible for payment on the account
      v. photo identification from country of origin,
      vi. a current photo identification from school or employer, or,
      vii. other information deemed sufficient by the Company to establish the Applicant's identification.
   e) Service address;
   f) Preferred mailing address; and
   g) Telephone number(s) where the Applicant may be reached.

B. **Nonresidential Applicants**

Sole proprietors must provide the identification required under (2)(A) of this rule as well as meet the credit requirements as established in Rule E. All other Nonresidential Applicants must provide the following information for the person(s) responsible for payment of the account:
1) Company name and, if applicable, name used for Doing Business As (DBA);
2) Service address;
3) Preferred mailing address;
4) State of incorporation;

RULE D (Concluded)

Nonresidential Applicants (Continued)

5) Name of an officer or other responsible employee;
6) A current, valid telephone number(s) where the officer or other employee named for (5) may be reached; and
7) A Federal Tax Identification Number.

3. Forms of Requests for Electricity Service

A. An Applicant may request Utility Provided Service from the Company by telephone, electronically or in person at one of the Company's offices. The Company has the discretion to require an Applicant to fill out and sign a written application form.
B. The Company may accept complete third party applications for residential Utility Provided Service. The Company may refuse to process such an application until it receives satisfactory evidence of the third party's authority to request such service.
C. When a Nonresidential Applicant selects Direct Access Service through an ESS, the ESS must submit a Direct Access Service Request (DASR) under the provisions of Rule K prior to initiation of Direct Access Service.

4. Effect of Application

An application does not bind the Company to provide service and does not bind the Applicant to remain a Customer for a period longer than the minimum term specified in the applicable rate schedule.

5. Customer Service Agreements

In most cases, the Company will not require a written Customer Service Agreement as a condition of providing Electricity Service. Certain rate schedules and Rule I of these General Rules and Regulations may require a written Customer Service Agreement.

6. Consequences of Accepting Electricity Service

Any person who occupies or is responsible for Premises where Electricity Service is supplied and/or delivered by the Company where the Company has no accepted current application for Electricity Service is liable for all charges for such Electricity Service, based on the applicable rate schedule. Such persons, however, do not have the rights and privileges accorded to Customers.

7. Refusal of Electricity Service

The Company may refuse an application for Electricity Service until it receives full payment of any past due amount or other obligation related to a Customer's/Applicant's prior account or as also set forth in OAR 860-021-0335.

RULE E
ESTABLISHING CREDIT / TREATMENT OF DEPOSITS

1. Residential Credit Standards

A. **Generally**

Before the Company accepts an application for Electricity Service, it may require the Applicant to establish credit standing. OAR 860-021-0200 (hereinafter referred to as "Commission Credit Rules") determines the criteria for establishing credit.
The establishment or reestablishment of credit under this rule does not relieve an Applicant or Customer from complying with all of the Company's rules and regulations on file with the Commission, making prompt payment of bills, and being subject to the discontinuance of Electricity Service for nonpayment.

B. **Establishing Credit**

A Residential Applicant may establish credit standing for new or continuing service by providing one of the following:

1) Submit an authorized letter from his/her previous electric utility, on the utility's letterhead, verifying all of the following:
   a) The dates the Applicant received service;
   b) That the Applicant was the responsible person on a service account where 12 months of continuous, equivalent Electricity Service was received within the prior 24 months;
   c) That the Applicant's service was not disconnected for theft, diversion of service or for tampering with utility facilities; and
   d) That the Applicant's service was not disconnected for nonpayment during the final 12 months that service was received.
2) If the Applicant has previously received Electricity Service from the Company, then the Company may verify the Applicant's creditworthiness based on the same standards listed above;
3) A letter from the Applicant's employer, income provider or authorized representative verifying the Applicant's ability to pay. A letter from an employer must state that the Applicant is currently employed and has been employed the entire 12 months prior to the application, and must contain a telephone number for an authorized representative of the employer. The Company must be able to verify the Applicant's employment; or

C. **Residential Deposit Not Required**

The Company does not require Residential Deposits starting May 9, 2022 consistent with Commission Order No. 22-129.

RULE E (Continued)

D. **Treatment and Refund of Residential Deposits**

The Company will furnish a receipt upon payment of deposit and will hold the deposit until credit is satisfactorily established or re-established. For the purposes of this section of the rule, credit is considered to be established or re-established if, at the end of 12 months after a deposit is paid in full:

1) The account is current;
2) The Customer has not been issued more than two 5 day disconnection notices during the previous 12 months; and
3) The Customer was not disconnected for nonpayment, meter tampering, or diversion of electricity service during the previous 12 months.

In the event the Customer moves to a new address within the Company's Service Territory and the Company is holding a deposit in accordance with this rule, the deposit, plus accrued interest, will be transferred to the new account.

E. **Interest Accrual**

Deposits will accrue interest at a rate prescribed by order of the Commission and set forth in Schedule 300. If a deposit is held beyond 12 months, accrued interest will be paid by a credit to the Customer's account on the next bill for service following the anniversary of the accrual date. Interest will be prorated on deposits held by the Company for less than a full 12 months.

F. **Delinquent Accounts**

When residential service is voluntarily closed, the Company will refund a Customer deposit with interest accrued at the rate as listed in Schedule 300, except that such refund will first be applied to reduce or eliminate any unpaid balance(s) on any other Customer account(s).
The Company is under no obligation to draw on deposits to cure delinquency of an active Customer account.

2. Nonresidential Credit Standards

A. **Generally**

Before an application for Electricity Service is accepted, the Company will require the Nonresidential Applicant or Customer to establish credit as defined below in this rule. The establishment or re-establishment of credit under this rule does not relieve an Applicant or Customer from complying with all of the Company’s rules and regulations on file with the Commission, making prompt payment of bills, and being subject to the discontinuance of Electricity Service for nonpayment.

RULE E (Continued)

B. **Privacy**

The Company treats credit, financial information or documentation received from Customer as confidential, and requires written or electronic permission from Customer before disclosing to any third parties. The Company will not release such information without such permission unless required by law or the Company in good faith believes such action is necessary to (1) comply with the law or legal process, (2) protect and defend the Company's rights or property or (3) protect the personal safety or property of the Company's other customers or the public.

C. **Establishing Credit**

1) A Nonresidential Applicant or Customer with 12 or more months of continuous and equivalent Electricity Service may establish credit for new or continuing service by:
   a) Demonstrating that immediately prior to the date of application, the Nonresidential Applicant or Customer did not, during that 12 months:
      (i) Receive more than two 5-day disconnection notices;
      (ii) Have service disconnected for non-payment,
      (iii) Owe an account balance from a prior account that when closed was not paid according to its terms;
   b) Demonstrating that in the previous 24 months prior to the date of application did not engage in meter tampering, theft or diversion of electricity service; and
   c) Demonstrating that in the 36 months prior to the date of application was not involved in an insolvency proceeding including but not limited to, bankruptcy, receivership, liquidation, bulk sale, or financial reorganization naming the Nonresidential Applicant, Customer, or any principals of the corporation, partnership, or Nonresidential entity as a debtor party to the filing.
      If the Nonresidential Customer or Applicant cannot demonstrate all of the above conditions, the Applicant or Customer must pay a deposit.
2) Where there is no account history, or fewer than 12 months of Company account history from which the Company can draw from in the establishment or re-establishment of credit, the Applicant or Customer may establish credit for new or continuing service by doing the following:
   a) Providing a form of security satisfactory to the Company; or
   b) Payment of a deposit.
   3) Where a Nonresidential Applicant or Customer has multiple accounts for Electricity service, the establishment or re-establishment of credit will be based on all Nonresidential account history and all such accounts must meet the above requirements.

RULE E (Continued)

D. **Maintaining Creditworthiness**

The Company may verify the Nonresidential Customer's creditworthiness at any time, which may include, but is not limited to, the Customer providing financial information or other documentation the Company deems necessary. If the Customer is unable to demonstrate creditworthiness, the Customer may be required to pay a deposit, or provide an acceptable form of other security as described in Section C(2). A lack of credit worthiness is demonstrated by, but is not limited to, public disclosure of significant financial losses; inability to make scheduled debt payments; disclosure of potential bankruptcy; foreclosure of assets by secured creditors or the sale of assets in order to fulfill secured credit obligations.

E. **Nonresidential Deposit Requirement**

A deposit equal to a maximum of two average month's billings for Company charges is required when the Nonresidential Applicant or Customer:

1) Does not satisfy the credit criteria as defined in Section (2)(C) of this rule;
2) Was previously exempted from paying a deposit based upon false information given at the time of application;
3) Was previously terminated for theft of service by the Company or was otherwise found to have tampered with Company facilities, or diverted utility service;
4) Owed an account balance that when closed was not paid according to its terms, or that service was involuntarily terminated.

In lieu of a deposit required under this Section E and at the Company's discretion, a Nonresidential Applicant or Customer may provide other security in a form which the Company finds reasonable and satisfactory in the establishment or re-establishment of credit. Terms and conditions of such security must be established and agreed to between the Company and the Applicant or Customer within the five days from the date the deposit is first required.

In the case of Nonresidential Applicants or Customers with seasonal usage, the maximum deposit amount will be based on the two highest months of usage.

RULE E (Continued)

F. **New or Additional Nonresidential Deposits**

A Nonresidential Customer may be required to re-establish credit where conditions of Electricity Service or the basis upon which credit was originally established have materially changed. A Nonresidential Customer's re-establishment of credit may lead to the requirement of a new or additional deposit, or an expansion of other forms of security. For the purposes of this rule, conditions are considered to have materially changed if any of the following exist:

1) The Nonresidential Customer's Electricity usage is such that, the Company does not have a deposit that equals 1/6 of the estimated annual usage where a deposit has been paid, or the Customer must establish credit at a different service address;
2) The expected billings to the Nonresidential Customer have changed as a result of the Customer's enrollment in Portfolio or other Electricity Service options;
3) The Nonresidential Customer returns to Standard Service from Direct Access Service or Emergency Default Service; or
4) Conditions in Subsection E are found to apply.

G. **Timing of Payment of a Nonresidential Deposit**

If the Nonresidential Applicant has an account balance from a prior service account that was not paid according to its terms, the Applicant must pay the required deposit either in full, or enter into a payment agreement within five business days of the service request. Failure to pay the deposit or enter into a payment agreement within the five days may result in the disconnection of service without further notice.

Absent an account balance from a prior service, if the service is connected at the requested service address, the Nonresidential Applicant must either pay the deposit in full or pay the deposit as it is billed for the new service regardless of whether or not the first month's billing is for a full Billing Period. Failure to pay the deposit may result in the disconnection of service following five days written notice.

If service is not connected at the service address; the Nonresidential Applicant must pay the deposit in full, or have entered into a payment arrangement before service is connected.

Where a non-cash deposit payment is paid to the Company and that payment is subsequently returned by the financial institution for insufficient funds, the Nonresidential Applicant or Customer is subject to service disconnection and will not obtain or retain Customer status. The Company will attempt to notify the Nonresidential Applicant or Customer of the returned payment and will provide a 5-day notice, either verbally or in writing, prior to disconnection.

RULE E (Continued)

Timing of Payment of a Nonresidential Deposit (Continued)

An existing Nonresidential Customer whose Electricity Service is disconnected for nonpayment of a deposit will be required to pay the full amount of the deposit, plus any applicable Reconnection Charge, Late Payment Charge, and any past due amount(s) before service is restored. Written notice of disconnection for nonpayment of deposit will be provided to Nonresidential Customers five days before service disconnection. The procedures in OAR 860-021-0505 will be used in issuing the notice of disconnection.

H. **Like Ownership**

If the Company, in its discretion, determines that principals of a corporation, partnership, or other commercial enterprise are substantially the same as another corporation, partnership, or commercial enterprise that either is receiving or has at one time received Electricity Service, they are deemed to be the same Nonresidential Applicant or Customer for the purpose of this Rule E.

I. **Treatment and Refund of Nonresidential Deposits**

The Company will furnish a receipt upon payment of deposit and will hold the deposit until credit is satisfactorily established or re-established. For the purposes of this section of the rule, credit is considered to be established or re-established and the deposit, with accrued interest, refunded to the Customer, if, at the end of 12 months after the deposit is paid in full:

1) The account is current; and
2) The Nonresidential Customer has not been issued more than two 5-day disconnect notices during the previous 12 months; and
3) The Nonresidential Customer was not disconnected for nonpayment, or was found to have engaged in theft, diversion of energy, or tampering with Company facilities, during the previous 12 months; and
4) The Company has determined that the condition which necessitated the deposit no longer impedes the Nonresidential Customer's ability to demonstrate creditworthiness and that no new condition or material change would require a deposit.

RULE E (Concluded)

Treatment and Refund of Nonresidential Deposits (Continued)

Prior to refunding the deposit, when a Nonresidential Customer has multiple accounts or one account that includes other products and services, the Company may review such accounts and contractual obligations to determine if unpaid past due balances are owed to the Company. The Company will not review any Residential electricity service accounts. The Company will first apply the refundable deposit and accrued interest to any such past due amounts. Any remaining balance, at the Customer’s option, shall be refunded or credited to any account or contractual commitment for which products and/or services were provided.

In the event the Nonresidential Customer moves to a new address within the Company's Service Territory and the Company is holding a deposit in accordance with this rule, the deposit, plus accrued interest, will be transferred to the new account.

J. **Interest Accrual for Nonresidential Deposits**

Nonresidential Customer deposits will accrue interest at a rate prescribed by order of the Commission and set forth in Schedule 300. If a deposit is held beyond 12 months, accrued interest will be paid by a credit to the Nonresidential Customer's account on the next bill for service following the anniversary of the accrual date. Interest will be prorated on deposits held by the Company for less than a full 12 months.

K. **Delinquent Accounts**

When a Nonresidential service account is voluntarily closed, the Company will refund the Nonresidential Customer deposit with interest accrued at the rate listed in Schedule 300, except that such refund will first be applied to reduce or eliminate any unpaid balance(s) on the Nonresidential Customer’s account(s) and under any contractual obligations it has with the Company. The Company is under no obligation to draw on deposits to cure delinquency of an active Nonresidential Customer’s account.

RULE F
BILLINGS

1. Basis for Billing

A. **Generally**

Unless specifically provided otherwise in a rate schedule or in a contract, the Company's rates are based upon the furnishing of continuous Electricity Service to the Customer's Premises at a single Service Point (SP), and at a single voltage and phase. If the Company agrees to additional SPs, each SP is separately metered and billed and treated as a separate Line Extension under the provisions of Rule I.

B. **Individual Metering**

Each separately operated business activity and each separate building is individually metered and billed except:

1) Where two or more buildings on one Premises are occupied and used by one Customer in the operation of a single and integrated business enterprise, the Company may furnish Electricity Service for the entire group of buildings through one service connection at one SP; and
2) Where a site has service measured and billed from a single meter, a Customer will furnish Electricity to the tenants on its Premises, provided the cost to the tenant for such Electricity is included as a general cost in the rent and is not separately billed or paid.

C. **Continuing Nature of Charges**

Disconnect and reconnect transactions do not relieve a Customer from the obligation to pay Basic or Minimum Charges that accumulate during the periods where the Company makes Electricity Service available but such service is not used by the Customer.

D. **Tax Adjustment**

A separately stated tax adjustment is billed in any community or area where a governmental authority imposes a tax or assessment in excess of the limit established by the Commission in OAR 860-022-0040 and 0045.

E. **Resale**

1) Electricity Service will not be supplied for resale, except on Premises and through installations where a Customer engaged in resale to tenants prior to November 5, 1973. In such cases, the Customer will bill the tenants at the Company's applicable rates or, if approved by the Company, at the Company's average rate per kWh (the Customer's total bill for Electricity including all charges, adjustments and taxes divided by the associated kWh).

RULE F (Continued)

Resale (Continued)

The Company will allow billing at the Customer's average rate when the Customer does not have adequate metering to bill tenants at applicable rates or the usage characteristics of the tenants do not lend themselves to standard billing.

2) Electricity service used for the exclusive purpose of transportation fuel is exempt from restriction of resale as directed by OPUC Order 12-013, which "*explicitly permits a customer to re-sell electricity as motor fuel consistent with ORS. 757.005(1)(b)(G)*".

2. Customer to be Billed; Responsibility for Payment

The Customer receiving Electricity Service is responsible for payment of all Company charges except when an ESS is providing consolidated billing as specified in Section (2) of Rule G. In such case, the ESS is responsible for payment of Direct Access Service and other Company charges. Customers are responsible for checking their billings and verifying their accuracy. When a change in occupancy occurs or the Customer otherwise chooses to close an account, the Customer must provide five business days' notice to the Company, before the change will go into effect. The Company may accept a change of occupancy notification from a third party. The Company may refuse to process a change of occupancy until it receives satisfactory evidence of the third party's authority to request such a change. The outgoing Customer (or serving ESS if it is providing a Consolidated Bill) is held responsible for all service supplied to the Premises until the account is closed.

3. Application for Site

In order for multiple accounts to be billed as a Site, the Customer must either obtain Site certification through the Oregon Department of Energy (ODOE) or request Company certification.

To request Company certification, the Customer must provide a list of all account numbers and maps or other supporting documentation to demonstrate that these accounts comprise a Site. The Customer will be required to sign and return a letter of understanding before any billing changes are effective.

As a Site, the Customer's primary account will be assessed the maximum $500 Schedule 115 charge. When the Customer's usage is seasonal, the Company will review the usage from all accounts comprising the Site and assess the maximum or less than the maximum charge as applicable. For nonseasonal Customers, if the combined usage from all accounts comprising the Site is such that the total Schedule 115 charge based on kWh would be less than $500 a month, the Customer is responsible to provide sufficient documentation to the Company in order to be refunded any overpayment. For purposes of Schedule 108, the Customer must be certified as a Site with ODOE and have completed a certified project. Once the project is certified, the Customer must notify and provide documentation to the Company before Schedule 108 billing changes will be made.

RULE F (Continued)

4.Meter Readings

A. **Generally**

The Company will keep a record of at least three years of meter readings. Meter readings are the basis for determining all bills rendered for metered service.

B. **Assessed Demand**

At the Company's option, Demand may be determined by test or assessment. The assessed Demand of each motor is the nameplate horsepower of the motor multiplied by 0.825 rounded to the nearest whole kW.

C. **Estimated or Prorated Meter Readings**

The amount of Electricity, Demand or Reactive Demand used by the Customer is estimated by the Company from the best available sources and evidence in the following circumstances:

1) Where a meter is inaccessible due to conditions on the Customer's Premises; or
2) When it is determined that the amount of Electricity, Demand, or Reactive Demand used was different from that recorded or billed; or
3) In preparing opening and closing bills. It is the normal practice of the Company, however, to make reasonable efforts to prepare opening and closing bills from actual meter readings.

D. **Incorrect Metering or Billing**

1) When Utility Service has been unmetered, incorrectly metered or billed, regardless of cause, the Company in accordance to OAR 860-021-0135, may adjust its billings and issue a corrected bill to collect under billed amounts or must issue a refund or bill credit for previous amounts over billed.
2) Except as provided in Section (5) of this rule, when an adjustment is necessary:
   a) The Company may rebill the Customer the correct amounts when an under billing is identified. The Company may not rebill for charges accruing more than two years before the date on which the Company identified the incorrect bill. The rebill may not include charges accruing more than 12-months from the date of the last incorrect bill.
   b) The Company must refund the Customer when an over billing is identified. The Company may not refund amounts overpaid more than three years before the date on which the Company identified the incorrect bill. The refund period may not include overpayments made more than 12-months from the date of the last incorrect bill.

RULE F (Continued)

Incorrect Metering or Billing (Continued)

3) The Company will provide written notice to the Customer detailing the circumstances of the adjustment, time period, the adjusted amount of an under or over-billing and the Commission’s dispute process. If an over-billing occurs, the Customer will have the option of a refund or a bill credit. For an under-billing, the Company will offer the Customer a time payment agreement or renegotiate the terms of an existing time payment agreement to include the under-billing. A time payment agreement will not apply if the under-billing is due to the conditions listed in Section (4) of this rule.
4) If the under-billing is the result of fraud, tampering, diversion, theft, misinformation, false identification or any other unlawful conduct on the part of the Customer or former Customer, the Company may bill for and collect the full amount owed to the Company without limitation.
5) The Company may waive re-billing or issuance of a refund when costs of taking such action are uneconomical or when a meter is found to be less than 2% fast or slow.

E. **Special Meter Reading**

The Special Meter Reading Charge, as set forth under Schedule 300, is applied when a Customer has requested more than one Special Meter Reading during the preceding 12-month period to verify the accuracy of a previous meter reading. If the Special Meter Reading results in a billing correction, the Company will waive the Special Meter Reading Charge.

F. **Unmetered Loads**

Electricity Service to fixed loads with fixed periods of operation, such as streetlights, Schedule 92 traffic lights, television amplifiers and other similar installations, may be unmetered for the convenience and mutual benefit of the Customer and Company. Monthly usage is billed in accordance with the Customer’s applicable rate schedule. Customers have the responsibility of notifying the Company of changes in connected load. Without such notice, the Company is not obligated to make retroactive adjustments to billings or continue to offer unmetered service to the fixed load.

G. **Special Demand**

All rate schedules are based upon loads for which standard Demand measurements reflect adequately the burden imposed on the Company's system. If a Customer has a load with large short-period fluctuations, the Company reserves the right to employ a Special Demand determination.

RULE F (Continued)

H. **Reactive Demand**

All rate schedules assume that the Customer takes a minimum of Reactive Demand. Charges in the rate schedules for Reactive Demand are separate from and in addition to charges under the monthly rate for Demand and Electricity or under any minimum charge. Where the Customer installs equipment to supply part or all of its Reactive Demand requirement, such equipment must be switched in a manner acceptable to the Company. Separate charges for Reactive Demand will not be made when the Customer's Reactive Demand is 30 kVar or less.

5. Presentation and Payment of Bills

A. **Generally**

The rate schedules in this Tariff set forth the rates for one Billing Period. However, the Company may read meters and render bills for a period shorter or longer than one Billing Period, in which case the charges based on one month of service (e.g. monthly Basic Charges, charges for Facility Capacity and other Demand related charges) and the number of kWh in each of the rate blocks of the rate schedules will be prorated by multiplying by the number of days in the period and dividing by 30. The number of days in the Billing Period must be less than 27 or more than 34 for a bill to be prorated.

B. **Prorating Initial and Closing Bills**

Initial and closing bills are prorated, unless the time between initial and final use of service is less than 27 days.

C. **Prorating for Tariff Changes**

Changes in Tariff charges or provisions which become effective with service rendered as of a particular date rather than upon the date of meter readings or billings are prorated based on the number of days during the Billing Period that service was provided under the former and revised rate schedules unless the Company is billing on a daily basis using daily readings.

D. **Payment of Bills**

All bills are due and payable 15 days from the date of presentation, unless otherwise specified on the bill. The date of presentation is the date on which the Company mails or transmits the bill.
Customers who meet eligibility requirements may request a due date different than the date designated for that customer's regular billing cycle. At no time will the actual due date be earlier in a calendar month than the date requested by the customer, but it may vary up to 7 days. A Customer may change their bill due date up to two times within a 12 month period.

RULE F (Continued)

Payment of Bills (Continued)

Non-cash payments remitted by Customers in payment of bills are accepted conditionally. A Returned Payment Charge, set forth under Schedule 300, is assessed when the Customer's financial institution refuses to pay as charged.
If a Customer's non-cash payment is returned by the Customer's financial institution within the last 12 months, future payments must be made in cash, money order, verified credit card payment or cashier's check.

PGE does not allow PGE employees to collect payments at the door.

E. **Processing of Payments**

The Company will allocate payments from Customers in the following order:
1) Past due deposits or installments;
2) Required deposits currently due;
3) Past due regulated charges for Electricity Services;
4) Current regulated charges for Electricity Services;
5) Past due charges for optional services by oldest date first; and
6) Current charges for optional services.

F. **Budget Pay Plans**

Budget Pay Plans are available to Residential and Small Nonresidential Customers who have satisfactory credit and have no past due balance on their account. No additional charges will be made for rendering bills under a Budget Pay Plan. The Company may adjust a Customer's budget pay amount if changes in the Customer's usage patterns or other factors cause the budget pay amount to no longer accurately reflect the Customer's actual billings.
The Company may discontinue a Customer's Budget Pay Plan if the Customer fails to pay the monthly budget pay amount in full by the due date. Customers may discontinue participation in the Budget Pay Plan upon notification to the Company. If a Budget Pay Plan is discontinued, the Customer must pay any unpaid balance determined by subtracting the total amount paid under the Budget Pay Plan from the total amount the bills would have been, based on the actual kWh used. If a budget pay plan is voluntarily or involuntarily discontinued, the Company is not obligated to offer another Budget Pay Plan to that Customer for a period of 12 months from the time the plan was discontinued.

Other monthly charges, such as financing contract and area light charges, will be added to the Customer's monthly bill but are not included when computing the monthly budget pay amount. The Company offers:

RULE F (Continued)

Budget Pay Plans (Continued)

1) **Equal Pay Plan**
The monthly payment amount is based upon 1/11 of the anticipated annual bill, adjusted as necessary for Tariff changes. After the annual equal pay anniversary date, the Customer will be charged or credited the difference between the actual usage and the forecasted usage in addition to the updated equal pay amount. Annually, Customer accounts are reviewed to determine the equal pay amount for the subsequent 12 months. Outside of the annual review, at the Customer’s request, a present account balance can be settled. Adjustments in the equal pay amount may be made by the Company at times other than annually if the Customer's actual bill would differ significantly from their previously calculated anticipated annual bill.

G. **Time Payment Agreements**

Residential Customers who are notified of pending disconnection may choose between two Time Payment Agreement options: a levelized payment plan and an arrearage plan as described in OAR 860-021-0415.

H. **Credit Balance**

Except where a Customer is on a Time Payment Agreement, an amount paid in excess of what is owed the Company for services rendered and other applicable charges will be carried as a credit balance on its account and applied to bills for future service unless the Customer requests a cash refund. When a customer on a Time Payment Agreement pays more than the billed amount, the excess payment will be applied to the principal due.

I. **Forced Shutdown of Customer's Operations**

If a Nonresidential Customer's productive operations are completely shut down for a continuous period of more than 15 days solely by reason of fire, flood, wind, action of the elements, acts of God, or other accident or casualty beyond the Customer's control, and the Customer so notifies the Company in writing immediately upon the Customer's knowledge of such event, any minimum charge provision of the applicable rate schedule will be waived during the time of such shutdown. During such time, bills will be computed on the basis of actual Demand and Electricity use and prorated to the number of days involved. The Customer will give notice to the Company prior to resumption of any productive operations.

RULE F (Concluded)

J. **Late Payment Charge**

A Late Payment Charge may be assessed to any account that is not paid in full each month. For Residential Customers, the Late Payment Charge will be computed as specified in Schedule 300 and applied to the delinquent balance no earlier than at the time of preparing the subsequent month's bill. A Nonresidential Customer may be assessed a late payment charge against any account that is not paid in full each month. A Late Payment Charge will not be applied to a Residential account with a Time Payment Agreement or a Budget Pay Plan that is current. A Late Payment Charge will not be applied to Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008.

K. **Bill History Information Service Charge**

Advance payment of the Bill History Information Service Charge, as specified in Schedule 300, is required for each year of requested prior bill information beyond the most recent 12 months. No charge is assessed when the billing information is required to resolve billing disputes filed with the Commission. Customers can access their interval usage data through their account on the Company's website. In the case where a Customer requests formatted and analyzed interval data, the charge specified in Schedule 300 will be based on a mutually agreeable charge.

RULE G
DIRECT ACCESS SERVICE AND BILLING

1. Direct Access Service

All Customers, except Residential, may elect to receive Direct Access Service from an ESS under the terms of the parallel Direct Access schedule (500 series). Direct Access Service is also an option for eligible Nonresidential Customers served on Schedules 485, 489 and 689.

A. **Enrollment**
Direct Access Service is only available upon acceptance of an Enrollment DASR by the Company. Prerequisites and notification requirements are as contained in each service schedule and Rule K.

B. **Emergency Default Service**
The Company will provide Emergency Default Service under Schedule 81 when an ESS or the Customer informs the Company that the ESS is no longer providing service or when the Company becomes aware that the Customer is no longer receiving service from the ESS and the Company has not received the 10 business day notice required for Standard Service under the appropriate schedule.

2. Special Requirements for Direct Access Billings

A. **Generally**

A Customer purchasing Electricity from an ESS may choose from two billing options: the ESS bills for all services (ESS Consolidated Bill) or the Company and the ESS each bill for their respective services (Company/ESS Split Bill).

1) **Company/ESS Split Bill**
When the Customer is receiving a Company/ESS Split Bill, the Company may disconnect Electricity Service for nonpayment of Direct Access Service under the guidelines set forth in Rule H.
2) **ESS Consolidated Bill**
When the Customer receives an ESS Consolidated Bill, failure of the Customer to pay the ESS for Direct Access Service does not relieve the ESS of the responsibility to pay the Company for Direct Access Services and any other Company charges.

B. **ESS Billing Responsibilities**

An ESS is responsible for the following:

1) Confirming receipt of Customer usage data within 12 hours of transmittal from the Company;
2) Responding to Customer inquiries regarding ESS charges; and
3) Under the ESS Consolidated Bill option, issuing a timely corrected bill to the Customer when the Company provides revised billing information.

RULE G (Concluded)

C. **Company Billing Responsibilities**

The Company will provide usage data to the ESS within two business days of the Customer's meter reading. When the ESS provides an ESS Consolidated Bill, the Company will provide bill-ready data within two business days of the Customer's meter reading. The Company is not responsible for computing or determining the accuracy of ESS charges.

D. **Information Included in Billing**

ESS billing for Customers will include the following information:

1) The beginning and ending dates of the Billing Period;
2) The number of units of service supplied;
3) The telephone number, identified as a Company number, to call for outage reporting and other local electrical utility matters;
4) The Service Point Identification (SPIDs) of the Customer;
5) The price and amount due for each service or product the Customer is purchasing;
6) Price, power source and environmental impact information in accordance with Oregon Administrative Rule 860-038-0300; and
7) The amount of the Public Purpose Charge, if any.
8) When the Customer receives an ESS Consolidated Bill, the bill will include the following additional information:
   a) Any tax adjustments;
   b) The amount of any transition charge or credit; and
   c) Mandated legal and safety notices in the format provided by the Company.

3. **Customer Responsibility**

Customers are responsible for checking their billings and verifying their accuracy. Questions regarding ESS charges must be directed to the ESS and questions regarding Company charges must be directed to the Company.

RULE H
DISCONNECTION AND RECONNECTION

1. Grounds for Disconnection of Electricity Service

Electricity Service may be disconnected:

A. When service is being received after having obtained Customer status through the provision of false identification or verification of identity;
B. Where Customer facilities provided are unsafe or do not comply with state and municipal codes governing service or the rules and regulations of the Company (OAR 860-021-0335);
C. Where the Customer does not cooperate in providing access to the meter (OAR 860-021-0120);
D. When a Customer requests the Company to disconnect or close an Electricity Service account (OAR 860-021-0310);
E. When a joint account is closed and any remaining Customer(s) fails to reapply for Electricity Service within 20 days, so long as the Company has provided a notice of pending disconnection;
F. Where dangerous or emergency conditions exist at the Premises [OAR 860-021-0315; OAR 860-024-0012(1)];
G. For failure to pay Oregon Tariff charges due for Electricity Service rendered [OAR 860-021-0405; OAR 860-021-0505];
H. For meter tampering, diverting Electricity Service or other Theft of Service;
I. For failure to abide by the terms of a time payment agreement [OAR 860-021-0410(6); OAR 860-021-0415(5)];
J. Where a Customer fails to disclose reasonable load information (860-021-0305); or
K. When the Commission approves the disconnection of Electricity Service.

2. Procedures for Disconnection and Reconnection of Electricity Service

The Company will discontinue and reconnect Electricity Service in accordance with the rules of the Commission. These rules, copies of which may be obtained from the Company, are contained in OAR 860-021-0057 and OAR 860-021-0305 through 860-021-0505.

A Field Visit Charge specified in Schedule 300 may be charged whenever the Company personnel visits a service address intending to reconnect or disconnect service, but due to customer action is unable to complete the reconnection or disconnection at the time of the visit. The first Field Visit Charge within a rolling 12-month period will be waived for Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008.

RULE H (Continued)

Procedures for Disconnection and Reconnection of Electricity Service (Continued)

A Customer who has avoided disconnection, established credit, or gained reconnection of Electricity Service by making a non-cash payment that is subsequently returned by the Customer's financial institution is subject to disconnection of such service. Prior to disconnection the Company must make a good-faith attempt to notify the Customer of the returned payment and that service will be disconnected without further notice if payment is not received within one business day. When remitting for dishonored funds, the Customer will make the payment in either cash, money order, cashier's check or verified credit card payment.

3. Credit Related Disconnection and Reconnection Charges

No charge is incurred for credit-related disconnection of Residential service. The Company may impose a charge for reconnection of Electricity Service to an Applicant to whom Electricity Service has been disconnected involuntarily. Applicants may call the Company's call center to fulfill the requirements for and request service reconnection. Regular Business Hours for the Company's call center are Monday through Friday, 7:00 a.m. to 7:00 p.m., excluding state-recognized holidays. Applicants who fulfill all the requirements for service reconnection, including making all necessary payments, incur one of the following reconnection charges as set forth in Schedule 300:

A. **Standard Reconnection**

The Standard Reconnection charge is incurred when a scheduled After Hours Reconnection is not requested and a qualified request for service reconnection is received. Standard reconnection requests will result in reconnection of service no later than the end of the next day following the business day on which the request for service is received or treated as received according to this rule. For the purposes of this rule, a business day is 8:00 a.m. to 5:00 p.m., Monday through Thursday, or 8:00 a.m. to 3:00 p.m. on Friday. Calls received after 5:00 p.m., Monday through Thursday* or after 3:00 p.m. on Fridays* are treated as if received at 8:00 a.m. the next business day.
The reconnection charge for the first two remote reconnections or first non-remote reconnection in a calendar year will be waived for Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008.

* Excluding State recognized holidays.

RULE H (Continued)

B. **After Hours Reconnection**

An After Hours Reconnection charge is incurred when a Customer requests that service be reconnected at after 5:00 p.m. Monday through Thursday**, after 3:00 p.m. on Friday**, or when service restoration is requested outside the parameters of when the Standard Reconnection charge would apply.

** Excluding State- and utility-recognized holidays.

4. Customer Requested Disconnection and Reconnection

Charges for service disconnection and reconnection are as listed in Schedule 300. At the Customer's request, the Company will disconnect and reconnect Electricity Service to ensure safe working conditions. The disconnection and reconnection will be done without charge if the work can be completed on the initial trip or on a second trip scheduled during Scheduled Crew Hours. If, at the Customer's request, the disconnection and reconnection are performed during other than Scheduled Crew Hours or for reasons other than to ensure safe working conditions, Schedule 300 charges for disconnection and reconnection apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In all other cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.

5. Generally

A. In cases where the disconnection is performed at the meter base, the charge for Reconnects at Meter Base will be imposed in order to reconnect service.
B. Should it become necessary to disconnect the Electricity Service at other than the meter base, the Schedule 300 charge for Reconnects at Other Than Meter Base will be imposed in order to reconnect service. Should this require a second trip to the premises to perform the disconnection, the charge for reconnects at Other Than Meter Base is in addition to the normal charge under Reconnects at Meter Base.
C. Should other than authorized Company personnel unlawfully reconnect the Electricity Service, an additional charge set forth in Schedule 300 is imposed.
D. No charge is imposed for a reconnection performed during Scheduled Crew Hours in order to provide Electricity Service to a new Applicant. If such a reconnection is performed outside of Scheduled Crew Hours, a charge set forth under Disconnection and Reconnection Rates of Schedule 300 is imposed.
E. In the case where a building owner or manager requests reconnection of Electricity Service for cleaning, showing the unit, or any other purpose other than to provide Electricity Service to an occupant, a charge for reconnection as specified in Schedule 300 will be imposed.

RULE H (Concluded)

Generally (Continued)

F. In cases where the Company has been requested to reconnect Electricity Service after it has been disconnected at the meter and the visit has not resulted in a reconnection of service due to Customer action or inaction, a Field Visit Charge is assessed as specified in Schedule 300. The first Field Visit Charge within a rolling 12-month period will be waived for Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008.

6. Nonwaiver of Right to Disconnect Service

The Company has the option, but is not obligated, to seek disconnection of Electricity Service if grounds exist. Delay or failure on the Company's part to exercise the option does not constitute a waiver of its right to do so at a later time.

7. Severe Weather Disconnection Moratorium

The Company will not disconnect service for nonpayment to a Residential or Small Nonresidential Customer when the weather conditions specified in OAR 860-021-0407(1),(2) or (3) are forecasted in the Company's service territory. This provision applies to the service territory specified in Rule A of this Tariff. The Company will observe forecasted temperatures daily and by 8:00 am each morning from the National Weather Service office in Portland, Oregon. The Company will resume disconnections for nonpayment during the next available business day as operational conditions allow. Upon request from Customers who have been disconnected for nonpayment within 72 hours prior to weather conditions specified in OAR 860-021-0407(1), (2) or (3), the Company will attempt to reconnect service. Reconnection fees authorized in OAR 860-021-0330 may apply.

8. Wildfire Displacement Disconnection Moratorium

The Company will make a best effort to not disconnect service for nonpayment to a Residential or Nonresidential Customer when the Customer is under a level 2 or 3 evacuation notice or the day after a level 2 or 3 evacuation notice has been lifted, as specified in OAR 860-021-0406(1) and (2). This provision applies to the service territory specified in Rule A of this Tariff. Upon request from Customers who have been disconnected for nonpayment within 72 hours prior to a level 2 or 3 evacuation notice, the Company will attempt to reconnect service. Reconnection fees authorized in OAR 860-021-0330 may apply.

9. Other Remedies

The Company reserves the right to pursue all other legal remedies available to it if grounds for disconnection of Electricity Service exist, whether or not it exercises its right to disconnect service.

RULE I
LINE EXTENSIONS

1. Purpose

This rule establishes procedures and defines respective cost responsibilities to provide a Line Extension to a builder, developer, Customer or Applicant who requests a Line Extension on its own behalf, or a Customer or Applicant's agent.

A. Generally

Line Extensions will be at primary and/or secondary voltage levels. Modifications to transmission or subtransmission voltage facilities or substations are not considered Line Extensions for purposes of this rule and require special contract arrangements.
When an agent requests a Line Extension on behalf of a Customer or Applicant, the agent must provide documentation acceptable to the Company evidencing its authority to request a Line Extension.

B. Definitions

1) **Applicant**
For purposes of this rule, an Applicant is a builder, developer, Customer, Applicant or other Customer or Applicant agent requesting a Line Extension to:
   a) Serve new construction; or
   b) Obtain additional capacity for, or a change in, service conditions relative to existing Distribution Facilities.
2) **Distribution Facilities**
Distribution Facilities are all structures and devices needed to distribute Electricity at any of the primary or secondary voltages listed in Rule C. Distribution Facilities will be installed in accordance with applicable laws, codes and Company standards and practices. It is the Applicant's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant to fully disclose its load requirement to the Company, the repair and, or replacement costs of such Facilities will be paid by the Applicant.

RULE I (Continued)

Definitions (Continued)

3) **Line Extension**
A Line Extension is the installation of new, additional or upgraded Distribution Facilities from a point on the Company's existing distribution system that the Company has determined has adequate capacity for the Applicant's planned Electricity needs to the Applicant's Service Point (SP). Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service, upgrades to existing primary lines will not be considered part of the Line Extension. Any new primary or secondary Line Extensions, transformer additions or replacements necessary to serve the new load will be considered part of the Line Extension. However, for residential Electric Vehicle charging-related line extensions, transformer additions or replacements necessary to serve that charging load will not be considered part of the Line Extension.

4) **Line Extension Allowance**
The Line Extension Allowance is the portion of the Line Extension Cost that the Company will provide without charge to the Applicant. Estimated annual kWh values used to calculate non-Residential Customer line extension allowances do not reflect onsite generation.

5) **Line Extension Cost**
A Line Extension Cost is the Company's total estimated cost to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs. Line Extension Costs are intended to recover the expenses of labor, material and equipment involved in the design, installation and inspection of the Line Extension. Line Extension Costs include, but are not limited to, labor costs, the cost of transformers, primary and secondary voltage conductors, tree trimming or tree removal, Company indirect charges and the cost of any necessary rearrangement of existing Facilities. Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service and the transformer requires upgrading, the Line Extension Cost will be credited for the estimated original cost, less depreciation, less removal costs, of the existing transformer. However, for residential Electric Vehicle charging line extensions, any transformer additions, or replacements necessary to serve the charging load will not be considered part of the Line Extension. Estimates of Line Extension Costs provided to Applicants are valid for six months from the date of issue. After six months the Company reserves the right to provide a revised estimate. The Line Extension Cost does not include payments to a third party for easements, additional costs associated with Underground Line Extension or other additional costs described in this rule.

RULE I (Continued)

Definitions (Continued)

6) **Long Side Service Connection**
A service connection, which runs parallel to the street, rather than perpendicular to the street.
7) **Primary Voltage Project**
A Primary Voltage Project is a planned undertaking of construction, where the Company initially installs only primary voltage facilities. Primary Voltage Projects include large lot residential subdivisions, industrial parks and other similar complexes. It is expected that within the project each Customer will be served from one or more transformers dedicated to that Customer's use.
8) **Public Thoroughfare**
A Public Thoroughfare is a municipal, county, state, federal, or other street, road, or highway, which is dedicated, maintained and open to public use in which the Company has the right to construct, operate, and maintain Facilities.
9) **Residential Subdivision**
A Residential Subdivision is a parcel of land divided into four or more smaller lots for the purpose of development or sale, which has been platted and filed under Oregon law as a subdivision. It is expected that within the subdivision several homes will be or are served from the same transformer.

B. **Company Requirements**

1) **Company to Determine Route**
The Company will determine the route for all Line Extensions along Public Thoroughfares and may determine the route of a Line Extension made on private property. If the Applicant requests a route different than that determined by the Company, the Company may provide the Line Extension along the requested route if the Applicant pays the Company all additional costs resulting from the provision of that route and the requested route is not contrary to Company standards and practices.
2) **Company Ownership**
The Company will own and maintain all Facilities to the SP.
3) **Company Installation**
The Company will install all Facilities to the SP except that an Applicant for overhead Facilities may arrange to have the Facilities located on the property constructed by an electrical contractor acceptable to the Company, subject to the following conditions:
   a) The Company will furnish the design and construction specifications for the connection and perform the necessary surveying;

RULE I (Continued)

Company Installation (Continued)

b) The Applicant will, prior to the beginning of construction, cause the contractor to furnish the Company a certificate naming the Company as an additional insured in an amount not less than $1 million under the contractor's general liability policy;
c) During and after completion of the work by the contractor, the Company will make inspections. If the construction meets the Company's design specifications, the Company will accept ownership, and the Applicant will provide to the Company the title to the construction, together with all rights-of-way and easements required by the Company, free and clear of any liens or encumbrances; and
d) Following receipt of the title, the Company will energize the Line Extension to make Electricity Service available to the Applicant.
e) If, within 24 months of the time the Company energized the Line Extension, it determines that the overhead Distribution Facilities are deficient in materials or workmanship, the Applicant must pay the cost to correct the deficiency to the Company's satisfaction.

4) **Unusual Distribution Facilities or Nonstandard Construction**
The Company is required to install only those Facilities deemed necessary to render service in accordance with the Tariff. The Company is not required to make Line Extensions which involve additional or unusual Facilities, nonstandard construction, or other unusual conditions. If, at the Applicant's request, the Company installs Facilities which are in addition to, or in substitution of, the standard Facilities which the Company would normally install but which are otherwise acceptable to the Company, the additional cost of such nonstandard Facilities will be paid by the Applicant and will not be subject to the Line Extension Allowance in Schedule 300. In the case of conversion from overhead service to underground service, Section 6 of this Rule applies. In the case of relocation or removal of services and facilities, Section 7 of Rule C applies.

2. Applicant Cost Responsibilities

A. **Payment**

Applicants who have cost responsibilities under this section and Section 3 will make payment in full at the time the Company agrees to make the Line Extension.
Applicant's payment requirements for jobs with Line Extension Costs estimated to be equal to or exceeding $250,000 may be as follows:

1) The Applicant will provide a cash payment of 10% of the estimated Line Extension Cost prior to the Company initiating design work;

RULE I (Continued)

Payment (Continued)

2) At the time the Company orders any special order and/or long lead-time electrical and/or pathway material, the Applicant will provide a cash payment to the Company for the full cost of the order; and
3) At the commencement of construction, the Applicant will provide a payment equal to any remaining Line Extension Costs necessary to complete construction. Acceptable means of payment will be at the sole discretion of the Company.

The Line Extension Allowance will be refunded at the time the Applicant's Electricity Service is established. If Applicant's Electricity Service is not established, payments made under Section (2)(A) are not refundable.

B. **Applicants for New Permanent Service**

1) **Individual Applicants**
Applicants for new permanent service will be responsible for the Line Extension Costs, less the applicable Line Extension Allowance listed in Schedule 300. In addition, any payments to a third party for easements, permits, additional costs associated with Underground Line Extensions, and all other additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.
2) **Other than Individual Applicants**
The Company will install a main-line primary distribution system to provide service to a project (e.g., a subdivision, industrial park, or similar project) to serve Customers within the project provided the Applicant pays in advance for: 1) the total estimated cost of the installation of a continuous conduit system which includes, but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits; and 2) all other Applicant cost responsibilities based on the expected load within the project. The expected load in a large lot subdivision, industrial park, or similar project is comprised of only those loads projected to be connected within the first five years. Any Line Extension refund owed to the Customer or Applicant will be based on load connected within the first five years.

In residential subdivisions or phases of residential subdivisions where Line Extensions will not require subsequent additional extensions of primary voltage Distribution Facilities to serve the ultimate users within the subdivision, the refund will be based on the Line Extension Allowances for the subdivision calculated in accordance with Schedule 300.

RULE I (Continued)

C. **Existing Customers**

1) **Nonresidential**
Where an Applicant is an existing Nonresidential Customer requesting an additional SP, the conversion of a single-phase service to three-phase service, or additional capacity, the Applicant will make payment in full at the time the Company agrees to make the Line Extension. The Line Extension Allowance in these cases will be based on the incremental, annual kWh to be served by the Company or, in the case of a change in the applicable rate schedule, equal to four times the increase in annual revenues from Basic and Distribution Charges.
2) **Residential**
Where an Applicant is a Residential Customer requesting additional capacity at the same SP, the Line Extension Allowance is as listed in Schedule 300. Any excess amount will be the responsibility of the Applicant. In addition, any payments to a third party for easements, permits and additional costs associated with Underground Line Extensions and all additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

3. **Special Conditions for Underground Line Extensions**

A. **Applicability**

Underground Line Extensions will be made:
1) When required by a governmental authority having jurisdiction;
2) When required by the Company for reasons of safety, resiliency or because the extension is from an existing underground system; or
3) When otherwise mutually agreed upon by the Company and the Applicant.

B. **Responsibility for Costs**

1) The Applicant will be responsible for the current and reasonable future costs associated with the installation of the Line Extension's continuous conduit system, which includes but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits. The Company will own and maintain the conduit system once Company conductors have been installed.
2) At its option, the Company may perform the Applicant's responsibilities listed in (B)(1) above at the Applicant's expense or permit the Applicant to perform these responsibilities at Applicant's expense. Where work is to be performed in an existing right-of-way and requires the Company to obtain a permit from a governmental body, the Company may specify additional requirements and place restrictions on the selection of contractors.

RULE I (Continued)

Responsibility for Costs (Continued)

3) Where the Company provides trenching, and backfilling, estimated actual costs will apply as specified in Schedule 300. The Applicant will be responsible for all additional costs of excavating rock, furnishing and installing raceway, excavating to a depth in excess of Company standards, manual digging, and the repair of paved roads, walks, and driveways when such work must be performed.

D. Additional Services

1) **Service Locates**
The Company will locate underground water, sewer and water runoff services along the Applicant's proposed trench route on the Applicant’s property if requested by the Applicant.
2) **Service Guarantee/Wasted Trip Charge**
The Company will begin the installation of residential single family underground service laterals within seven working days following the date an Applicant requests such service, except during periods of major storms or other such conditions beyond the Company's control. If the Company does not meet this standard, the Company will pay the Applicant the Service Guarantee Charge in Schedule 300. If, however, Company resources are dispatched to install the residential single family service lateral within the seven-day period and the Applicant's site or other facilities are not ready for service, the Applicant will be assessed the Wasted Trip Charge in Schedule 300.
3) **Joint Trench Installation Charge**
Upon mutual agreement between the Company and the Applicant, the Company may install telephone and cable services during the installation of the underground service lateral. The parties involved will mutually agree to the price for such service.

RULE I (Continued)

4. Refunds

A. Where an Applicant has paid all or a portion of the costs of a Line Extension and additional Customers are subsequently connected to it, the Company will, at its initiative or on request from the Applicant for the original Line Extension, compute on a prorated basis the Line Extension Cost responsibility for up to three additional new Applicants connected to the original Line Extension and make collections and refunds for up to three additional Applicants, provided the following three conditions are satisfied:
   1) The original Line Extension has been in service for less than five years when the additional connections are made;
   2) The original Line Extension has been in service less than six years when the application for refund is made; and
   3) The payment made by the original Applicant was $100 or more.

B. Where additional Applicants are connected within five years of completion of the original Line Extension, and the allowances for the subsequent Line Extensions exceed additional Applicants' costs, the difference may be refunded to the original Applicant under the following conditions:
   1) Application for such refunds may be made as additional Applicants are connected, but no more frequently than on an annual basis; and
   2) The total amount refunded will not exceed the Line Extension Cost paid by the original Applicant.

5. Special Conditions for Portland River District Undergrounding Project

For an area within the City of Portland, depicted as the shaded region on the map included as Appendix A[(1)], the applicable Applicant cost responsibilities of Underground Line Extensions, as specified in Section (3)B(1), will be incurred as a Service Connection Charge. This charge will be equal to $39,040.00[(2)] for a standard 200' X 200' block within the district. For any development area other than the standard size, the charge will be prorated based on the comparative size of that area.

(1) Between Broadway and Glisan Street and behind Union Station, the River District boundary is defined by the railroad right-of-way. Their respective streets or the Willamette River defines all other sections of the River District boundary.

(2) This amount will be applicable through the year 2009. Beyond 2009, the charge will be escalated annually by the Company's then authorized cost of capital.

RULE I (Continued)

6. Conversion from Overhead to Underground Service

A. General

The Company will replace overhead with underground Facilities whenever such conversion is practicable and economically feasible. Customers connected by overhead Distribution Facilities owned by the Company that desire underground service will comply with applicable provisions of this rule.

B. Payment for Service Changes

The party requesting conversion from overhead to underground will pay the Company, prior to conversion, the estimated original cost, less depreciation, less salvage value, plus removal expense of any existing overhead Facilities no longer used or useful by reason of said underground system, and the costs of any necessary rearrangements, modifications, and additions to existing Facilities to accommodate the conversion of Facilities from overhead to underground.

C. Special Conditions

The conversion of overhead to underground Facilities affecting more than one Customer will be conditioned on the following:

1) The governing body of the city or county in which the Company's Facilities are located will have adopted an ordinance creating an underground district in the area in which both the existing and new Facilities are and will be located, providing:
   a) All existing overhead communication equipment and Distribution Facilities in such district are removed;
   b) Each Customer served from such electric overhead Facilities will, in accordance with the Company's rules for underground service, make all necessary electrical facility changes on said Customer’s Premises in order to receive service from the Company’s underground Facilities as soon as available; and
   c) The Company is authorized to discontinue its overhead service on completion of the underground Facilities.
2) All Customers served from overhead Facilities will agree in writing to perform the wiring changes required on their Premises so that service may be furnished in accordance with the Company's rules regarding underground service. Such Customers must also authorize the Company to discontinue overhead service upon completion of the underground Facilities.

RULE I (Continued)

Special Conditions (Continued)

3) When the local government requires the Company to convert overhead Facilities to underground at the Company's expense, the provisions of OAR 860-022-0046 will apply.
4) That portion of the overhead system that is placed underground will not impair the utilization of the remaining overhead system.

D. **Cost of Area Conversions**

Area conversions may involve an allocation or assessment of costs and responsibilities among Customers. Such assessment and collection thereof will be the responsibility of a governmental unit or an association of those affected.

E. **Cost of Additional Circuit Capacity**

Where the Company installs an underground circuit with capacity in excess of the existing overhead, any additional cost to provide such excess circuit capacity will be at the Company's expense. Applicant cost responsibilities will be as defined in Section (6)(B) plus all reasonable costs for conduit or vault space installed to establish pathways for future circuit capacity.

7. Nonpermanent Line Extension

A. **General**

A Line Extension is nonpermanent when the Company believes service for its intended purpose by the Applicant will continue for less than five years. If the Company believes a requested Line Extension is nonpermanent, the Company will require a cash advance of the entire Line Extension Cost, plus payments to third parties for easements and those costs outlined under Section 3, plus the estimated cost of removing the Line Extension, less any salvage value. If service is used for the intended purpose by the Line Extension Applicant for a period of five years, that portion of the amount advanced by the Applicant which was in excess of the amount that would have been charged for a permanent Line Extension will be refunded to the Applicant with interest.

RULE I (Concluded)

B. **Greater than 1 MWa Nonresidential Nonpermanent Service**

Nonresidential Line Extension Applicants with Line Extension Costs of $50,000 or greater, with loads in excess of 1 MWa, will sign a contract agreeing to accept Electricity Service at a specified minimum load. If service is terminated within an initial term of five years or if service is reduced to shut-down mode, a Service Termination Charge equal to the Line Extension Allowance (LEA) less 1/5th for each year service was taken at the specified minimum will be assessed as follows:

$$\left[\frac{(5 - \text{Years Served})}{5} * \text{LEA}\right]$$

8. Excess Capacity

Excess Capacity will be determined to exist where:

A. The characteristics of the Customer's load require the Company to install Facilities larger than the kVA demand of the load for voltage regulation or other reasons;
B. The Customer requests additional capacity due to planned expansion needs that have not yet occurred; or
C. The Customer requests Facilities that are in excess of what the Company determines is required based on the Company's analysis of the Customer's planned load.

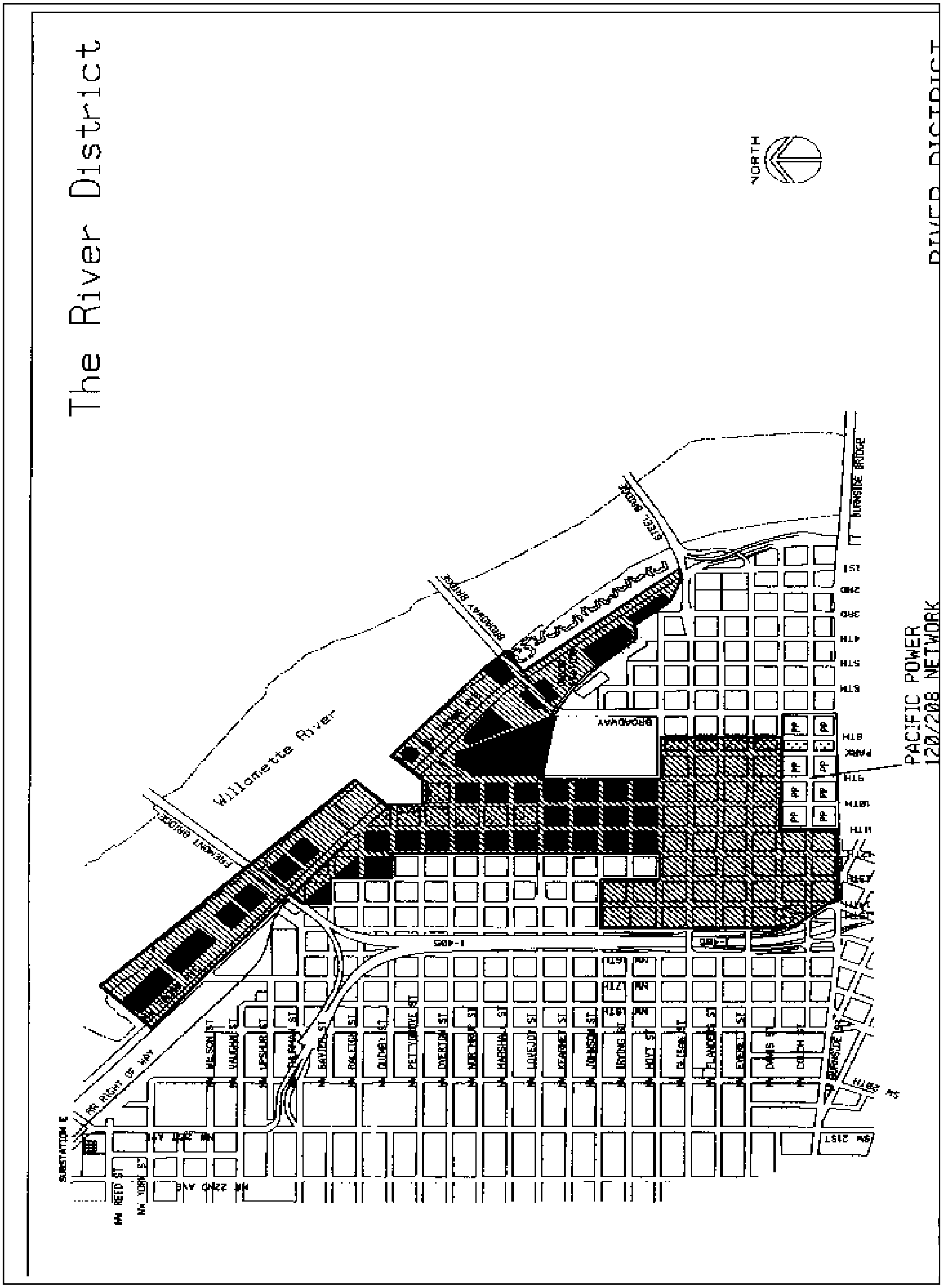
When a Customer applying for a service upgrade or a new service Applicant requires Excess Capacity, such installation will be ineligible for a Line Extension Allowance associated with the unused or underutilized portion of the Line Extension. The unused or underutilized portion of the Line Extension will be determined by comparing the cost of the Line Extension with and without the Facilities necessary to serve the Excess Capacity. The Customer or Applicant will also be responsible for a maintenance charge equal to the present value of future maintenance of the excess Facilities at the time the new service or service upgrade is installed. If within five years of installation the excess capacity situation is determined to no longer exist the Company will refund the portion of the Line Extension charges that resulted from the designation of Excess Capacity, including the maintenance charge. It is the responsibility of the Customer to inform the Company as to the change in their capacity requirement within the five-year period.

9. Rules Previously in Effect

Amounts advanced under the conditions established by a rule or contract previously in effect will be refunded in accordance with the provisions of that rule or contract.

RULE I

APPENDIX A


The River District
NORTH
Willamette River
BROADWAY BRIDGE
FREMONT BRIDGE
STEEL BRIDGE
BURNSIDE BRIDGE
BROADWAY
I-405
PACIFIC POWER
120/208 NETWORK
SUBSTATION E
RR RIGHT OF WAY
NW REED ST
NW YORK ST
NW 22ND AVE
NW 21ST
NW 21ST AVE
NW WILSON ST
NW VAUGHN ST
NW UPSHUR ST
NW THURMAN ST
NW SAVIER ST
NW RALEIGH ST
NW QUIMBY ST
NW PETTYGROVE ST
NW OVERTON ST
NW NORTHRUP ST
NW MARSHALL ST
NW LOVEJOY ST
NW KEARNEY ST
NW JOHNSON ST
NW IRVING ST
NW HOYT ST
NW GLISAN ST
NW FLANDERS ST
NW EVERETT ST
NW DAVIS ST
NW COUCH ST
NW BURNSIDE ST
1ST
2ND
3RD
4TH
5TH
6TH
8TH
PARK
9TH
10TH
11TH

RULE J
STANDARD SERVICE AND PORTFOLIO OPTIONS

1. Standard Service

A. **Eligibility**

A Nonresidential Customer may select Standard Service.

B. **Enrollment**

Standard Service will automatically be provided to a Large Nonresidential Customer who has received Emergency Default Service for five business days and/or does not select Direct Access Service. A Small Nonresidential Customer that is receiving Direct Access Service may move to Standard Service upon 10 days' notice to the Company. A Large Nonresidential Customer may choose Direct Access Service during an election window and in accordance with the terms and conditions specified in Rule K. A Customer moving to or from Direct Access will be charged a Switching Fee as specified in Schedule 300.

C. **Term**

A Large Nonresidential Customer must remain on Standard Service until he/she has met the notice and term requirements of the Standard Service option selected.

2. Portfolio Options

A. **Eligibility**

A Residential or Small Nonresidential Customer is eligible for service under one or more Portfolio Options in addition to the Standard Cost of Service as contained in the applicable rate schedule.

B. **Enrollment**

Residential and Small Nonresidential Customers may select a Portfolio Option via telephone, in person, over the Internet or by other Company-approved means. The Portfolio Enrollment Charge as specified in Schedule 300 will be incurred for any requested portfolio enrollment change other than the initial enrollment and the first requested change per year.

RULE K
REQUIREMENTS RELATING TO ESSs

1. Purpose

A. Generally

Prior to providing Electricity Service to Customers, an Electricity Service Supplier (ESS) must be certified by the Commission, if applicable, and meet the Company's requirements for providing service. The Company may provide information to the Commission certification process, if applicable, regarding the ESS's scheduling capabilities, electronic data transmission capabilities, insurance coverage and credit.

B. Requirements for Providing Service

To provide Electricity to a Customer an ESS must:

1) Be certified by the Commission, if applicable;
2) Complete the Company's business application form and submit an Application Processing Fee or Renewal Fee as listed in Schedule 600;
3) Establish creditworthiness as set forth in the ESS Credit Requirements provision of this rule;
4) Demonstrate the capability to meet the information exchange requirements of the Company.
5) Name the Company as an additional insured in the amount of at least $10 million on the ESS's general liability policy;
6) Execute an ESS Service Agreement with the Company confirming the terms and conditions of the service(s) elected and agree to abide by the terms and conditions of the Company's Tariff and the Oregon Administrative Rules;
7) If a Scheduling ESS, execute a transmission service agreement under the Company's Open Access Transmission Tariff; and
8) If a Non-Scheduling ESS, provide the name of the Scheduling ESS.

2. ESS Credit Requirements

A. Credit Review/Applicability

An ESS's participation in Direct Access Service is contingent upon meeting and maintaining the credit requirements set forth in this Tariff and the applicable ESS Service Agreement. The Company will determine whether the ESS meets the Company's initial creditworthiness requirements as set forth below, and advise the Commission whether the ESS has been credit approved or not. The Company will enter into an ESS Service Agreement after ESS's credit has been established, collateral has been obtained and ESS certification by the Commission is complete. The Company will continue to monitor the ESS creditworthiness to determine continuing compliance under the minimum credit requirements.

RULE K (Continued)

Credit Review/Applicability (Continued)

B. **Credit Exposure**

An ESS must establish and maintain creditworthiness relative to the Company's credit exposure to the ESS. Credit exposure will include, but not be limited to, the expected liabilities of the ESS.

C. **Establishment of Credit**

An ESS must establish its creditworthiness as described below.

1) **Creditworthiness Requirements**
Each ESS, or guarantor, must meet the Company's creditworthiness requirements by satisfying all of the criteria below. An ESS who cannot meet the requirements below will provide a collateral deposit as described in item (4) below.

a) **Credit Evaluation**
An ESS seeking to enter into a new ESS Service Agreement with the Company must complete a credit application to provide the financial information necessary to conduct a credit evaluation and establish the ESS's initial credit profile. The Company may require an ESS to complete a new or revised credit application if the ESS's ESS Service Agreement has been terminated, was not renewed, or in any other manner was caused to lapse; if the ESS no longer meets the minimum credit criteria; or periodically based on the Company's standard commercial practice.
The credit evaluation will be conducted by the Company. This evaluation will be completed within 10 Business Days from the Company's receipt of a completed credit application and all relevant financial statements. All information required to evaluate credit will remain strictly confidential between the ESS and the Company, except as otherwise required by law. The Company will notify the Commission of its credit decision upon completion of the Company's credit review. All credit evaluations and associated collateral deposit calculations performed by the Company will be done in a non-discriminatory and consistent manner.

b) **Required Credit Information**
Each ESS and guarantor (if applicable) will be required to provide the following information: (1) completed credit application; (2) three years of annual, audited financial statements; and (3) the latest interim financial statements along with the same interim financial statements from the prior year.

RULE K (Continued)

Establishment of Credit (Continued)

c) **Rating Agency**
An ESS and guarantor (if applicable) must demonstrate a current and maintained long-term, senior unsecured debt rating of Baa3 or higher from Moody's Investor Service (Moody's) or BBB- or higher from Standard and Poors (S&P).

d) **Tangible Net Worth**
An ESS and guarantor (if applicable) must maintain a minimum Tangible Net Worth of $750 million dollars and demonstrate a minimum Tangible Net Worth of $750 million dollars for the prior two-year period. Tangible Net Worth is defined as net worth minus intangibles such as goodwill and rights to patents or royalties.

e) **Credit History**
An ESS and guarantor (if applicable) must not be currently in default under any of its agreements with the Company or under any of its other agreements, and must be current on all of its financial obligations. An ESS and guarantor (if applicable) must pay all past due amounts owed to the Company before credit is established.

2) **Unsecured Credit**
For an ESS and guarantor (if applicable) whose creditworthiness is established by satisfying the above requirements, an unsecured credit limit may be established by the Company.
The Company may increase or decrease the unsecured credit limit on a case by case basis using accepted commercial credit standards and based on the following criteria: (1) adequate financial statements: (2) credit payment history; and (3) business fundamentals, which includes review of (a) market position; (b) litigation and contingencies; (c) organization; and (d) strategic and financial support. The Company will monitor the established creditworthiness utilizing these factors on an on-going basis.

3) **Collateral Requirements**
The ESS will be required to post or increase collateral under any of the following conditions:
a) The ESS does not meet the minimum creditworthiness standards established above;
b) The ESS fails to provide the Company sufficient relevant credit and financial information on an ongoing basis as required in this Tariff and the ESS Service Agreement;

RULE K (Continued)

Collateral Requirements (Continued)

c) The ESS experiences a material adverse change. A material adverse change is defined as the occurrence of any of the following events: (1) the ESS's long-term senior, unsecured debt rating is downgraded by either S&P or Moody's below BBB- and Baa3, respectively, or (2) a change in condition (financial or otherwise), net worth, assets, or properties which can reasonably be anticipated to impair the ESS's ability to fulfill its payment and credit obligations; or

d) The Company's total credit exposure to the ESS exceeds the ESS's unsecured credit limit and/or any existing Collateral Deposit.

4) **Collateral Deposits**

If collateral is required, the ESS will submit and maintain a collateral deposit as described below.

a) **Amount of Collateral Deposit**

The amount of the collateral deposit required to establish credit will be the sum of the following amounts as applicable:

(i) For ESSs billing customers for services provided by the Company, three times the estimated maximum monthly customer charges owed by the ESS to the Company, where such estimate is based on the usage and Tariff prices expected to prevail over the next 12 months;

(ii) All other charges from the Company to an ESS as estimated over a 90 day period; and

(iii) All invoiced and non-invoiced receivables due from the ESS; or

(iv) Not less than $500,000.

b) **Form of Collateral Deposit**

Collateral deposits will be in the form of (1) cash deposits, (2) Letters of Credit, defined as irrevocable and renewable issued by a major financial institution acceptable to the Company, or (3) guarantees, with guarantors who have a long-term senior, unsecured debt rating of Baa3 or higher from Moody's or BBB- or higher from S&P, unless the Company determines that a material change in the guarantor's creditworthiness has occurred, or, in other cases, through the credit evaluation process described above.

c) **Collateral Deposit Payment Timetable**

ESSs are obligated to post collateral deposits with the Company prior to entering into an ESS Service Agreement. Collateral deposit increases and/or adjustments must be received within two calendar days of a request from the Company. Collateral deposits must be established, maintained or extended within five days of expiration of a collateral deposit.

d) **Interest on Cash Deposit**

The Company will pay interest on cash collateral deposits. Interest will be calculated according to the interest rate prescribed in Schedule 300.

RULE K (Continued)

Establishment of Credit (Continued)

5) **On-going Maintenance of Credit**
   a) The Company may review the ESS's creditworthiness, credit limits and the Company's credit exposure on a daily basis. The Company may request an increase in the collateral deposit by providing notice to the ESS that an increase is required as the ESS enrolls additional Customers, the ESS no longer satisfies the minimum criteria commensurate with its unsecured credit line as described above, the Company draws on the collateral deposit or a portion of the collateral deposit pursuant to this Section or the ESS Service Agreement, and/or the Company's credit exposure to the ESS increases.
   b) To assure continued validity of established unsecured credit, the ESS will promptly notify the Company if the ESS (i) experiences any material adverse change; (ii) has its long-term, senior unsecured debt rating downgraded by Moody's and/or S&P; (iii) experiences a change in control as a result of merger or consolidation; (iv) sells or transfers a material portion of its assets; or (v) proposes to change its designation from Non-Scheduling to Scheduling or vice versa.
   c) The ESS will provide to the Company an updated credit application reflecting current financial and business information pursuant to the terms of this Section; upon the occurrence of any event listed in Section (2)(C)(3)(c); if the ESS has been suspended pursuant to the terms of the ESS Service Agreement; to support a request for an increased credit line; or as the Company may reasonably require on a quarterly basis.
   d) The ESS will review and maintain its collateral and establish, extend or increase collateral when required pursuant to this Section.
   e) All collateral amounts will be adjusted up or down to the nearest integral multiple of $25,000, but never less than the required initial collateral deposit at the time the ESS enters into and signs an ESS Service Agreement. The Company will notify the ESS of any needed adjustments.
6) **Re-establishment of Credit**
   An ESS whose ESS Service Agreement has been suspended due to inadequate credit may re-establish its creditworthiness in the manner prescribed in item C above.

D. **Additional Documents**

The ESS will execute and deliver all documents and instruments (including, without limitation, security agreements and Company financing statements) reasonably required from time to time to implement the provisions set forth above and to perfect any security interest granted to the Company.

RULE K (Continued)

3. Electronic Data Transfer Interchange (EDI)

All electronic communications between the Company and the ESS must conform to industry standard electronic data interchange protocols. The ESS must demonstrate its ability to successfully exchange test data for all transactions before the first Direct Access Service Request (DASR) is processed. The ESS will also provide a point of contact to resolve daily electronic data interchange problems. If the ESS is certified, but does not have active enrollments within a six-month period, the Company will request that the ESS retest the interchange.

The ESS must notify the Company of plans to modify its electronic data interchange systems such as the installation of new software or upgrades to software as well as any plans to change system subcontractors when such plans may affect data transfers between the Company and the ESS. The Company may require retesting of data transfers under such circumstances. Where retesting is required, the ESS will be subject to the set-up and verification charge contained in Schedule 600.

When the Company makes any changes to its interchange systems or changes subcontractors, it will promptly notify all ESSs. If the changes require retesting of systems, the Company will not charge ESSs for this testing.

4. Electricity Service Supplier Decertification

A. **Notice to ESS**

The Company may recommend to the Commission decertification of an ESS that the Commission has certified at times other than the annual renewal date. The Company will notify the ESS that it is initiating such action, if applicable.

B. **Criteria for Recommending Decertification**

The Company may recommend decertification, if applicable, of an ESS to the Commission when the ESS fails to comply with the terms and conditions under this Tariff, or fails to perform obligations under the transmission service agreement or ESS Service Agreement. The following are examples of when the Company may recommend decertification of an ESS:

1) Failure to submit an Electricity Schedule that meets the requirements of Section 11;
2) Failure to deliver Electricity according to its Electricity Schedule;
3) Submission of a DASR not authorized by a Customer;
4) Failure to conform with industry electronic data interchange protocols;

RULE K (Continued)

Criteria for Recommending Decertification (Continued)

5) Failure to comply with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) operating procedures;
6) Failure to pay for services rendered by the Company;
7) The ESS makes a general assignment or arrangement for the benefit of creditors;
8) The ESS becomes bankrupt, a debtor in a bankruptcy proceeding, insolvent, however evidenced, or is unable to pay its debts as they fall due;
9) The ESS files a petition or otherwise commences a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it;
10) The ESS has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets;
11) Evidence that indicates the ESS has violated any state or federal customer protection laws or rules, including antitrust laws, during the past three years;
12) The ESS has materially failed to meet its obligations under terms of the ESS Service Agreement so as to constitute an event of default;
13) The ESS engages in unauthorized use of Electricity or a Customer of the ESS engages in unauthorized use of Electricity and the ESS knew about it;
14) Failure to provide a complete, accurate and truthful credit application;
15) Failure to maintain credit requirements; and
16) At the general discretion of the Company.

C. **Notice to Customers**

The Company, upon consultation with the Commission, may transfer the ESS's Customers to the applicable Utility Provided Service prior to ceasing to provide service to the ESS. The Company will notify the ESS's Customers of the transfer in writing as soon as possible. The ESS will be charged a Switching Fee for each Customer transferred as listed in Schedule 600.

D. **Decertification**

Upon decertification, the ESS may no longer serve Customers, and all amounts billed or owed by the ESS are immediately due. The Company will move all Customers served by the ESS to Emergency Default Service and the ESS will be charged the Switching Fee listed in Schedule 600 for each Service Point (SP) that moves to Emergency Default Service.

RULE K (Continued)

5. Pre-enrollment Information Provided to ESS

With the Customer's authorization, the Company may provide account-specific information, including one year of monthly usage history but excluding credit information, to an ESS. The ESS will be charged the ESS Web Portal Data Access Fee as listed in Schedule 600 for such requests.

6. Customer Enrollment

A. **ESS/Company Relationship**

The ESS may not state or in any way imply that it has been given preferential status by the Company.

B. **ESS Liability**

The ESS will defend, indemnify and hold the Company harmless against all claims of loss made by any Customer arising from claims of inappropriate switching from the Company or another ESS in violation of the solicitation or verification provisions of the Commission, regardless of whether the person or entity doing the marketing or solicitation was an independent contractor of the ESS.

C. **Enrollment DASR**

The ESS must submit to the Company an Enrollment DASR which, at a minimum, includes the Customer's name, Company account number, service address, mailing address, type of service being purchased, name of the ESS, name of Scheduling ESS if different, proposed effective date, Customer's billing preference, and Service Point Identification (SPID) for each Customer that elects service from the ESS.

1) Unless the Company deems otherwise, the Company will activate only one (1) Enrollment DASR per SPID per meter reading cycle. When multiple Enrollment DASRs for the same SPID are received during the same meter reading cycle, the Company will activate the first Enrollment DASR received. The Enrollment DASR must be submitted at least 13 business days prior to the effective date. The Company will notify the ESS of Enrollment DASR acceptance or rejection within three business days of its receipt. For Enrollment DASRs submitted during an enrollment window, the three business day notice period does not begin until the end of the enrollment period. The Company will notify the ESS as to the date the Customer will begin Direct Access Service once interval metering is verified.

RULE K (Continued)

Enrollment DASR (Continued)

2) The Company will charge the ESS the Switching Fee listed in Schedule 600 for each Enrollment DASR received whether accepted or rejected.
3) Upon acceptance of an Enrollment DASR the Company will provide notice within three business days to the Customer’s current ESS, if any, of the pending change to a new ESS.

D. **Refusal of Enrollment DASR**

The Company may refuse to accept an Enrollment DASR when:

1) The Company has not received full payment from the Customer for past-due amounts or other obligations owed by it related to regulated charges from the Customer’s prior Electricity Service account(s) unless such charges are part of a pending Customer dispute;
2) The Company has not received full payment or the Customer has not made an arrangement to pay the balance owed by the Customer on an existing Budget Payment Option or other agreements;
3) The Enrollment DASR is not accurate and/or complete;
4) The ESS has not complied with provisions of the ESS Service Agreement;
5) The Customer has not completed any term obligation under Standard Service; or
6) The ESS is not certified by the Commission.

E. **Change DASR**

A Change DASR must be submitted when the ESS is requesting a modification. The Change DASR requires up to 13 business days to process. The Change DASR may only be submitted after receipt of the assigned effective date of the information subject to modification and must be submitted at least 13 business days prior to the requested effective date of the Change DASR. There is no charge for submitting a Change DASR. However, when a Change DASR is submitted to change the assigned enrollment effective date to a date that is not a regular meter read date, a Change of Effective Date charge as listed in Schedule 600 will be imposed.

F. **Other DASRs**

The Other DASR forms are as follows:

RULE K (Continued)

Other DASRs (Continued)

1) **Rescind DASR**
A Rescind DASR is a request to withdraw an Enrollment DASR and it must be submitted prior to the issuance of an Direct Access effective date. No charge is assessed for a Rescind DASR. A Rescind DASR requires three business days to process. If the Company does not have three business days to process before the effective date is issued, a Cancel DASR is required.
2) **Cancel DASR**
A Cancel DASR is a request for cancellation of Direct Access Service that has been submitted after the Direct Access Service effective date has been issued. No charge is assessed for a Cancel DASR. A Cancel DASR requires three business days to process. Failure to provide adequate notice may require the Customer to take Direct Access Service and/or move to Emergency Default Service until processing is complete.
3) **Drop DASR**
A Drop DASR is a request to stop Direct Access Service and return to Standard Service or to close the service account. A Drop DASR must be submitted at least 13 business days before the requested effective date. Failure to provide adequate notice may require the Customer to continue Direct Access Service and/or move to Emergency Default Service until the Drop DASR process can be completed. The Customer or ESS, whichever initiates the Drop DSAR, is charged the Switching Fee as listed in Schedule 300 or Schedule 600.
The Company may submit a Rescind, Cancel, or Drop DASR on behalf of the Customer to nullify an Enrollment DASR submitted for a Customer without their consent. The Customer will not be charged the Schedule 300 Switching Fee and the Customer's service will not be switched regardless of the required processing timeframes described above.

G. **<u>Customer Information</u>**

The Customer consents to the release by the Company to its ESS monthly usage data when it agrees to take Direct Access Service. Upon acceptance of an Enrollment DASR, the Company may provide to the ESS account-specific information, including one year of monthly usage history, excluding credit information.

RULE K (Continued)

H. **Return of Customer Deposits**

Following acceptance of an Enrollment DASR, the Company will return any Customer deposit, net of any amounts owing when the ESS is providing Consolidated Billing. When the Company is continuing to bill the Customer or the Customer has requested split billings between the ESS and the Company, the Company will retain the portion of the deposit appropriate for two months of regulated Electricity Service billings from the Company and credit the excess deposit, if any, to the Customer's account.

I. **Customer Change of Location**

When a Customer moves 100% of its operation from an existing service location enrolled under Direct Access to a [single] new service location and elects to continue Direct Access Service at such new service location ("Change of Location"), the Customer's ESS must submit a Drop DASR for the existing/old service location and an Enrollment DASR for the new service location. Customer requests for a Change of Location will not be considered should the change occur more than 12 months after the old location has been vacated, regardless of whether the service at such old location is nominal or idle or has been discontinued.
The following additional criteria will be applicable to a Customer's Change of Location:

1) The Customer and the ESS must provide written notice to the Company of the intended Change of Location. After processing the written request, the Company will notify the ESS when to send the Drop DASR for the existing/old location and the Enrollment DASR for the new location;
2) For a customer with multiple locations, the projected monthly consumption patterns of the new location will be similar to the prior location;
3) The account for the existing/old location must be: (1) closed, (2) placed on the PGE Daily Price Option prior to the new location receiving service under the terms and conditions of the applicable direct access schedule, (3) idle (i.e. no usage), or (4) placed on Cost of Service with demonstrated nominal use consistent with a vacated location. The Schedule 128 Annual Short-Term Transition Adjustment will apply to the old location if the account is placed on the PGE Daily Price Option under the second option. With respect to the third and fourth options, the Customer carries the burden to demonstrate that the old location is idle or the usage at such location is nominal and consistent with the location being vacated;

RULE K (Continued)

Customer Change of Location (Continued)

4) For Schedules 485, 489, and 490, the new location must be expected to have a Facility Capacity of at least 250 kW;
5) Consistent with the terms and conditions of Customer's Long-Term Cost of Service Opt-Out Agreement, the enrollment period vintage of the existing/old location and the associated Schedule 129 Long-Term Transition Adjustments will be transferred to the Customer's new service location, as applicable;
6) The new service location may be temporarily served under the provisions of the PGE Market Based Pricing Option until such time that the transfer of service location may be effectively executed;
7) The ESS will pay all applicable Schedule 600 charges.

7. ESS Service to Single Service Point

Only one ESS may serve any single Service Point (SP). If the Customer is receiving products and services from more than one ESS, the ESS that submitted the accepted Enrollment DASR is responsible for the coordination of services including, but not limited to billing, payment, delivery and scheduling.

8. Discontinuance of ESS Service

Upon determination by an ESS that it will discontinue service to a Customer because of nonpayment of charges or other reasons provided for in the ESS/Customer Agreement, the ESS will provide the Company with ten business days' notice of such discontinuance. The Company will subsequently move the Customer to Standard Service in the absence of an accepted Enrollment DASR. The Switching Fee listed in Schedule 600 will be charged to the ESS in conjunction with moving the Customer to Standard Service.

9. Company Billings to the ESS

The ESS is responsible for payment of all charges assessed to it by the Company. All bills issued under this Tariff are due and payable through electronic payment within 15 days of presentation. Billings unpaid by the due date are subject to a late payment charge as described in Schedule 600. When the ESS disputes charges assessed to it by the Company, the ESS is still responsible to make payment of such charges within 15 days of presentation.

RULE K (Continued)

10. Processing of Payments

Unless otherwise specified, the Company will allocate payments from ESSs in the following order:

1) Past due deposits or installments;
2) Required deposits currently due;
3) Past due regulated charges for Electricity Services;
4) Current regulated charges for Electricity Services;
5) Past due charges for optional services by oldest date first; and
6) Current charges for optional services.

11. ESS Scheduling Responsibilities

At least one day prior to the Day of Flow, in accordance with the ESS Service Agreement and transmission service agreement, each Scheduling ESS will provide the Company with an Electricity Schedule of the expected aggregated hourly load requirements of the Customers for which it has scheduling responsibility subject to the following terms and conditions:

A. **Scheduling Period: Day of Flow**

Each daily scheduling period will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

B. **Changes in Load**

The Company may require a Scheduling ESS to change its Electricity Schedule if the Company determines the Electricity Schedule does not adequately represent the expected ESS Customer load. If a Customer or Customers are served under an interruptible arrangement by the ESS, the ESS will notify the Company of any interruption coincident with its notification to those Customers and will adjust its Electricity Schedule accordingly.

C. **Failure to Schedule**

An ESS that fails to submit an Electricity Schedule is subject to applicable charges and immediate termination of the ESS Service Agreement. The Customers served by the ESS will be moved to Emergency Default Service.

RULE K (Continued)

D. **Confirmation**

The Company reserves the right to confirm with appropriate transmission service providers each Electricity Schedule provided by ESSs and to reject any Electricity Schedule that cannot be confirmed.

E. **Conformance with Regional Requirements**

The ESS will conform to FERC, NERC and WECC scheduling, operating and reporting requirements.

F. **ESS Control Information**

An ESS that chooses to self-provide ancillary services will provide the Company a real-time load and power factor signal via electronic means.

12. Company Scheduling Responsibilities

A. **Change in Load**

The Company will notify an ESS as soon as practical of a planned outage when such outage affects its Customer(s) with a load greater than one megawatt.

B. **Major Outage Procedures**

The Company will attempt to maintain system balance during a major outage using all appropriate methods available according to utility practices. The Company may require an ESS to reduce its Electricity Schedule in the event of a major loss of load due to a major outage consistent with the Company's resources. In such case, the Company will notify the ESS when it can resume normal scheduling. The Company will waive related imbalance penalty adjustment provisions during such event. The Company is responsible for responding to inquiries related to major outages. Customers who contact their ESS regarding major outages should be referred to the Company.

13. Settlement

The Company will reconcile total Electricity delivered by the ESS with the total Electricity consumed by the Customers for which the ESS has scheduling responsibility in accordance with Schedule 600 of this Tariff. Customer Electricity consumption will be measured accordingly:

RULE K (Continued)

A. **Interval-Metered Electricity**

Where the Customer has an interval-meter installed, Electricity consumed is equal to the metered quantity plus losses as specified in Schedule 600.

B. **Profiled Electricity**

Where interval-meter data is missing, hourly consumption will be estimated using load profiles and adjusted based on available metered data plus losses as specified in Schedule 600. For unmetered loads, consumption will be based on a test or estimated from equipment ratings, adjusted for losses, and allocated to each hour based on hours of usage and whether the equipment is operational during that hour.

14. Operational Order to Deliver Electricity

A. **General**

An “Operational Order to Deliver Electricity” may be issued by the Company upon one hour’s notice for purposes of maintaining the integrity of its electrical distribution system.

B. **Action by the ESS**

Upon receiving an Operational Order to Deliver Electricity, the ESS will endeavor to deliver its full capability for all its Customers served by adjusting its Electricity Schedule.

C. **Compensation**

The Company will waive all energy imbalance service charges and penalty provisions for an ESS that demonstrates substantial compliance with an Operational Order to Deliver Electricity. Compensation for excess Electricity delivered in accordance with the Company’s Operational Order to Deliver Electricity will be at a rate equal to the higher of:

1) The ESS’s direct cost of such Electricity; or
2) The highest incremental cost of Electricity purchased by the Company during each hour of the Operational Order to Deliver Electricity.

RULE K (Concluded)

15. Preemption

In addition to an Operational Order to Deliver Electricity, the Company may take automatic or manual actions that, in its opinion, are necessary or prudent to protect the performance, integrity, reliability or stability of its electrical system or any electrical system with which it is interconnected. During such period, delivery of Electricity to Customers may be curtailed or interrupted by the Company even though the ESS continues to supply Electricity to the Company. The payment for such Electricity will be made at a rate equal to the higher of:

A. The ESS's direct cost of such Electricity; or
B. The highest incremental cost of Electricity purchased by the Company during each hour of the preemption.

16. Dispute Resolution

A Dispute Resolution process is contained in the ESS Service Agreement.

RULE L
SPECIAL TYPES OF ELECTRICITY SERVICE

1. Service of Limited Duration (Temporary Service)

A. Definition

"Service of Limited Duration" or "Temporary Service" means Electricity Service to a Customer who, in the Company's opinion, will not continue to receive service for the minimum of five years.

B. Availability

Service of Limited Duration includes installations requiring only an overhead service drop, a service lateral to existing underground Facilities, or service to Premises where Facilities are in place, whether or not a meter setting is required. Charges will be in accordance with Schedule 300. Where Facilities other than those specified above are needed to provide service, the provisions of Rule I, Line Extensions, will apply.

1) The Company provides Standard Temporary Service as well as an optional Enhanced Temporary Service subject to the following conditions.
   a) Standard Temporary Service will be provided to Applicant-supplied service entrance equipment in accordance with applicable codes and regulations. Electricity Service will be metered and billed according to the applicable rate schedule until the account is closed or converted to permanent service.
   b) Nonresidential Customers may receive Standard Temporary Service from an ESS and are required to pay for the installation and removal of interval metering and meter communications (telephone or other method) necessary to deliver such service.
   c) Enhanced Temporary Service is provided on an optional basis for the construction of residential single-family and multi-family dwellings in underground service areas. Under Enhanced Temporary Service, the Company will provide and install an unmetered service pedestal for use until the permanent service is installed.
   d) The fixed charges for Enhanced Temporary Service specified in Schedule 300 include Electricity usage for up to 6 months. After 6 months Customers may extend Enhanced Temporary Service at additional 6-month time periods at the fixed renewal charge specified in Schedule 300. After 24 months, a permanent connection is required.

RULE L (Continued)

Availability (Continued)

C. In order to qualify for Enhanced Temporary Service, the Applicant must agree to the following:
1) Service will be used only for lights, tools, and equipment necessary for the construction of residential dwellings;
2) Service will not be used for the operation of permanently installed appliances or equipment or to heat or dry structures under construction;
3) For multi-family construction, the number of unmetered service pedestals can vary depending on the necessary service outlets per units/buildings under construction; and
4) Unless the trenching or boring work is provided by the Company under the terms of Schedule 300, the Applicant will provide a continuous underground conduit, suitable for Electricity Service, from the permanent meter base to the location of the Enhanced Temporary Service pedestal for the Company to use in later providing the permanent service.

In the event that Enhanced Temporary Service is used for purposes other than those specified, the Company will estimate the amount of Electricity used and bill according to the applicable rate schedule. The Company may restrict future availability of Enhanced Temporary Service in such cases.

2. Emergency Service

A. **Definition**

"Emergency Service" means Electricity Service supplied or made available to load devices which are operated only in emergency situations or in testing to respond to such situations. Electricity Service for freeze protection or similar applications likely to occur annually and/or only in the coldest time of the year is not an Emergency Service.

B. **Availability**

Emergency Service will be provided only to permanent Customers. Where the Company must furnish, install and maintain additional or specific facilities or capacity to provide Emergency Service, the Customer must pay the entire cost of the Line Extension and is ineligible for the Line Extension Allowance as described in Rule I. The Customer is also responsible for a maintenance charge equal to the present value of future maintenance of the facilities at the time the service is installed. Where the Customer modifies its usage and consistently uses the service at its transformer rating within a five year period, the portion of the Line Extension charges that resulted from the designation of Emergency Service including the maintenance charge will be refunded to the Customer.

RULE L (Continued)

3. Intermittent Use Service

A. **Definition**

"Intermittent Use Service" means continually available Electricity Service which a Customer uses intermittently for a short duration and at a high Demand level such that standard Energy or Demand measurement does not adequately reflect the burden imposed on the Company's equipment and facilities. Examples of Intermittent Use Service include service to test facilities, elevator or hoist motors, welding equipment, x-ray equipment and whole house instant or tankless hot water heaters with a Demand of 18 kW or greater.

B. **Availability**

Intermittent Use Service will be furnished only to permanent Customers. Where the Company must furnish, install, and maintain additional or specific facilities or capacity to provide Intermittent Use Service, the Customer must pay the entire cost of the portion of the Line Extension associated with such service and is ineligible for a Line Extension Allowance for that portion of the service. The Customer is also responsible for a maintenance charge equal to the present value of future maintenance of the facilities at the time the service is installed. Where the Customer modifies its usage and consistently uses the service at its transformer rating within a five year period, the portion of the Line Extension charges that resulted from the designation of Intermittent Use Service including the maintenance charge will be refunded to the Customer.

4. Alternate Service

A. **Definition**

"Alternate Service" means Electricity Service to a Customer from a second independent primary voltage circuit for which the Company provides a second path for supply of service in the event of the failure of the first electrically independent circuit. Alternate Service facilities include, but are not limited to, the substation and distribution line capacity reserved for the Customer's exclusive use, plus any additional metering or switching equipment required which is beyond the Company's normal responsibility.

RULE L (Continued)

B. **Availability**

The Company will provide Alternate Service at the request of a Customer who demonstrates a requirement for a higher than normal degree of service continuity. The Company will maintain Alternate Service to the best of its ability consistent with the need to operate and maintain its overall distribution system and will notify the Customer if the Alternate Service is to be discontinued for any extended period of time. Alternate Service will be provided only under a contract between the Company and a Customer.

C. **Contract Provisions**

Alternate Service contracts will provide generally as follows:

1) The Customer will specify its Alternate Service kVA Demand requirement and the period of time for which Alternate Service is required;
2) The design and arrangement of both the preferred and alternate circuits will be at the option of the Company. The Customer will install and maintain an automatic transfer switch. The characteristics, arrangement, and operation of such switch and the associated circuits will be subject to the Company's approval.
3) The Customer will pay the Company either a monthly charge or a lump sum payment to cover the Company's cost to provide the Alternate Service. The rate of the monthly charge, per kVA of alternate capacity required, will be the levelized future revenue requirements imposed on the Company by its investment in Alternate Service facilities and all future maintenance of those facilities. The lump sum amount will be the present worth of the items used to determine the monthly charge.
4) The kVA Demand on the Alternate Service will be measured by separate kW and kVAr Demand meters. Should the Customer impose a kVA Demand on the Alternate Service facilities that is in excess of the amount contracted for, the Customer will pay the Company an additional monthly charge per kVA of excess Demand for that month and the succeeding 11 months. The amount will be determined by multiplying the excess Demand by the monthly rate per kVA as determined in (4)(C)(3) above. In addition to this monthly charge, the Customer must either promptly modify plant operation to prevent future excess kVA Demand or execute a supplemental agreement with the Company for the additional amount of Alternate Service required. The facilities cost for Alternate Service will be based on the costs of the Company in effect at that time and will be calculated and billed as determined in (4)(C)(3). The Customer will be billed the actual cost of any damage to the Company's facilities caused by the Customer's Alternate Service Demand in excess of the contracted amount.

RULE L (Continued)

Contract Provisions (Continued)

5) The Customer may terminate the agreement for Alternate Service upon 30 days' written notice to the Company. If the Customer is making monthly payments for the Alternate Service, it will, upon termination, pay to the Company the amount that the Company's present-day investment in such facilities exceeds the value to the Company at that time. A Customer who has made a lump sum prepayment to the Company will, upon termination, receive from the Company an amount equal to the current value to the Company for those facilities dedicated to the Alternate Service. Such amount will not exceed the amount of the initial prepayment.

D. **Existing Alternate Service Customers**

Unless otherwise specifically provided, a Customer receiving Alternate Service on or before August 1, 1975 will continue to receive Alternate Service without charge subject to the conditions listed below.

1) Should the nature of the Premises change, Alternate Service without charge will be discontinued after 30 days' written notice by the Company.
2) Should an additional investment be required of the Company to continue to furnish Alternate Service, the Customer will be so notified and given the option of limiting the kVA Demand of Alternate Service required to that which is available from the Company at no charge or executing an agreement with the Company for Alternate Service in accordance with this rule.
3) Should a Customer receiving Alternate Service without charge modify its facilities such that an increase in Alternate Service requirement occurs, the Customer must execute an agreement with the Company for Alternate Service in accordance with this rule.

5. Distribution Facilities Service

A. **Definitions**

"Distribution Facilities Service" means the installation, operation, maintenance and ownership by the Company of Distribution Facilities that are dedicated solely to service on a Customer's site for the Customer's exclusive use, and located on the Customer's side of the Service Point (SP). "Distribution Facilities" includes primary and secondary cable, distribution transformers, and associated equipment terminating at Customer-owned service entrance or meter base for each building or structure.

RULE L (Continued)

B. **Availability**

The Company will provide Distribution Facilities Service on an optional basis to Customers with a minimum installed transformer capacity of 500 kVA as mutually agreed to by contract between the Company and Customer. Upon request of a Customer and agreement by the Company, Distribution Facilities Service will be provided to an existing Customer-owned distribution facilities installation subject to all conditions of this rule and subject to Company determination that the existing system meets Company Distribution Facilities requirements.
If the Customer's existing system does not meet the Company's current standards but is otherwise acceptable to the Company, with respect to safety and reliability, the Company may choose to offer Distribution Facilities Service to the Customer provided that a mutually agreeable plan to upgrade the system, as necessary, is developed and included in the Distribution Facilities Service Charge.

C. **Contract Provisions**

Distribution Facilities Service contracts will provide generally as follows:

1) **Distribution Facilities requirements**
The Distribution Facilities, on the Customer's side of the SP, will meet Company distribution system requirements in a manner consistent with Company practices, Company overhead and underground construction standards, applicable standards of the National Electric Safety Code (NESC), American National Standards Institute (ANSI) and the Oregon Electric Service Requirements.
2) **Facilities design and installation**
The design and arrangement of the Distribution Facilities will be as agreed to by the Customer and the Company. The Company will generally meter Electricity Service at the SP.
3) **Memorandum of Agreement**
A Memorandum of Agreement will be filed with the appropriate county in order to provide notice of the existence of the Distribution Facilities Service contract.
4) **Access**
The Customer will provide the Company access to the Distribution Facilities on the Customer's premises without restrictions or structural impediments for purposes of maintenance and repair of the Distribution Facilities.

RULE L (Concluded)

Contract Provisions (Continued)

5) **Distribution Facilities Service Charge**
The Customer must pay the Company a monthly charge to cover the Company's cost to provide the Distribution Facilities Service. The rate of the monthly charge will be the levelized revenue requirements imposed on the Company by its investment in Distribution Facilities and all future maintenance of those facilities. This charge is in addition to any charges for the furnishing or delivery of Electricity to the SP. No Line Extension Allowance as described in Rule I will be applied to Distribution Facilities.

6) **Load Requirements**
The Customer will promptly notify the Company of any changes in electrical load. The Customer will reimburse the Company for all costs of modification, replacement or repair of any transformers or other Distribution Facilities necessitated by increased electrical load.

7) **Maintenance and Repair**
The Company and Customer will be responsible for components of maintenance and repair as set out in the contract. All modifications or enhancements to the Distribution Facilities will be performed by the Company unless otherwise agreed to, in writing, by the Company.

8) **Termination**
The Customer may terminate the contract for Distribution Facilities Service upon purchase of the Distribution Facilities at a purchase price specified, and on terms set out, in the contract or as otherwise mutually agreed upon. Transfer of Distribution Facilities to Customer ownership may occur only after the Distribution Facilities have been approved by local authorities as meeting all applicable codes and requirements for such non-utility owned distribution facilities. Any costs to modify the facilities are the obligation of the Customer.

RULE M
METERING

1. Generally

A. Company Responsibility

The Company will own/lease, install, test, read, remove, replace and maintain meters for each Customer receiving metered Electricity Service. The meters and any meter transformers installed remain the Company's property and may be removed by the Company upon discontinuance of service.

B. Customer Responsibility

The Customer will, at Customer's expense, furnish, install and maintain the meter socket and all raceways and enclosures necessary to accept the Company's meters and metering transformers. The Company will provide metering transformers when required for installation by the Customer. The Customer will exercise proper care to protect Company property installed on the Premises, will not break the Company's seal or seals, and will pay for all loss or damage to such property caused by the Customer's negligence or misuse.

The Customer must grant the Company free and unrestricted access to the Premises at all reasonable times for purposes of inspecting, testing, reading, repairing, removing or replacing any or all metering equipment of the Company.

C. Meter Accuracy and Testing

The Company will, at a Customer's or Electricity Service Supplier's (ESS) request, test the accuracy of the registration of a meter once per 12-month period. If a Customer or ESS requests such a meter test more than once in a 12-month period, the Company will impose a Meter Test Charge as listed in Schedule 300. The Company will refund to the Customer or ESS the Meter Test Charge if the meter is found to be more than 2% fast or 2% slow.

2. Metering Requirements

A. Standard

The Company will install at the Customer's Service Point (SP) a meter capable of registering kWh usage. Meters capable of registering Demand, Reactive Demand, and time of use or interval usage will be installed when required due to the Customer's Electricity usage or rate schedule.

RULE M (Continued)

B. **Interval Metering**

The Company will meter Electricity usage in intervals of 30-minutes or less for Customers that purchase Electricity Service from an ESS, with the exception of unmetered loads. Where an interval meter does not exist at the time the Company receives a Direct Access Service Request (DASR), the Company has 30 days from the date the DASR is accepted to install such meter. Once installed, the Customer may begin purchasing Electricity from the ESS. A Customer who would not normally receive interval metering may, at its request, have an interval meter installed at the charge established in Schedule 300.

C. **Pulse Output Metering**

The Company will provide a connection to its metering facilities to supply kWh data pulses to Customer-owned load control equipment. The Company will also supply a Demand interval timing pulse, provided the Customer's load-control equipment is of the ideal curve or forecasting type. A Customer may have a pulse output metering installed for the charge established in Schedule 300.

D. **Nonstandard Metering Requested by ESS**

The Company installs metering that corresponds to the Customer's Electricity usage and rate schedule requirements. If an ESS requests that the Company offer a specific meter capability, function or metering service not currently supported, the Company must approve or deny the request within 10 days. If the request is approved, the Company will file with the Commission to offer such meter or metering service within 30 days. If the request is denied, the ESS may appeal the decision to the Commission.

E. **Residential Non-Network Meter**

1) Upon request of a Residential Customer, the Company will install at the Residential Customer's SP, a non-network meter. Non-network meter does not have the capability to record, store or transmit customer interval load data. The Company will charge the customer the cost of a Special Meter Reading as specified in Schedule 300. If the Customer is not the owner of the premises, the Customer must provide authorization from the owner to the Company. The Company will charge the Customer the Company's costs of owning, installing, maintaining and reading the non-network meter. Prior to the Company's installation of the meter at the Customer's premises, the Customer must pay the cost of installation in full. The non-network meter installation charge and recurrent charges are set forth in Schedule 300.

RULE M (Continued)

Residential Non-Network Meter (Continued)

2) A Customer may request a non-network meter for that Customer's premises only.
3) If in the Company's opinion access to the meter is restricted, the Company will seek the Customer's cooperation through mutual agreement in obtaining unrestricted access. If agreement cannot be reached and access remains restricted, disconnection of service could result after reasonable notice is provide.
4) Customers with non-network meters are not eligible for time-of-use rates and may be excluded from participating in future Company offered programs, for which a network meter is required.

3. Meter Location

A. **Generally**

Meters are to be installed on the outside of buildings at a location which is easily and conveniently accessible by Company personnel and by the Company's distribution lines; however, with the Company's prior approval, meters for nonresidential buildings may be located indoors if accessible to Company personnel during Scheduled Crew Hours.

B. **Locating Meter on Company's Pole, Pad, or Vault**

If no satisfactory location for the meter is available on or in the Customer's building, the meter and related equipment may, at the Company's option, be installed on the Company's pole or in a Company vault or enclosure. In such event, the Customer will pay the charge specified under Meter Installation Rates of Schedule 300.

C. **Unrestricted Access to Network Metering Equipment**

When in the Company's opinion the meter's communication signal/mechanism is impeded because of customer action or inaction, the Company may require the Customer, at the Customer's expense, to relocate the meter socket to a location satisfactory to the Company.

RULE M (Concluded)

D. **Metered on the Non-Service Side of Transformation**

If the Company installs or maintains the metering equipment on the primary voltage side of the meter and the Customer is receiving service at secondary voltage, billing will be based on meter registration less 1-1/2%. If the meter is located after the occurrence of transformation, and the Customer is receiving service at primary voltage, the billing will be based on meter reading plus 1-1/2%. These billing adjustments compensate for transformer losses or gains.

E. **Customer Options for Relocating Residential Meter**

A Residential Customer and owner of the premises may request that installed metering equipment be relocated to a different location on the Customer's property if acceptable to the Company. The Customer will incur the cost of relocating the meter as described in Schedule 300.

RULE N
CURTAILMENT PLAN

1. Purpose and Overview of the Curtailment Plan

This plan identifies the process by which the Company would initiate and implement load curtailment during a protracted regional Electricity shortage to ensure uniform treatment of all regional Customers. This plan would be activated only when declared necessary by State authorities. The goal of this plan is to accomplish Curtailment while treating Customers fairly and equitably, minimizing adverse impacts from Curtailment, complying with existing State laws and regulations, and providing for smooth, efficient and effective Curtailment administration.

2. Definitions

The following definitions apply to terms used in this plan:

A. **Base Billing Period**
One of the Billing Periods that comprises the Base Year. Base Billing Period data are weather-normalized before being used to calculate the amount of Curtailment achieved.

B. **Base Year**
Normally, the 12-month period which immediately precedes imposition of State-initiated load curtailment.

C. **Critical Load Customer**
A Customer that supplies essential services relating to public health, public safety, welfare, or Electricity production.

D. **Curtailment**
Reduction in Electricity usage irrespective of the means by which that reduction is achieved.

E. **Curtailment Target**
The maximum amounts of Electricity that the Customer may use and still remain in compliance with State Action. The Curtailment Target is figured individually for each Customer by Base Billing Period.

F. **Excess Power Consumption**
The lower of the following two values for loads subject to penalty:
   1) The difference between the Customer’s actual (or metered) consumption level during a Billing Period and the Curtailment Target; or
   2) The difference between the Customer’s weather-normalized Electricity usage during a Billing Period and the Curtailment Target.

G. **General Use Customer**
Any Nonresidential Customer who purchased less than five average megawatts (43,800 MWh) during the Base Year.

RULE N (Continued)

Definitions (Continued)

H. **Major Use Customer**
A Customer who purchased more than five average annual megawatts (43,800 MWh) during the Base Year.

I. **Plan**
The Curtailment Plan.

J. **Region**
The states of Washington, Oregon, and Idaho, and those portions of Montana that are west of the Continental Divide and/or within the Balancing Authority area of Northwestern Energy.

K. **Regional Plan**
The Regional Electric Energy Curtailment Plan as adopted by the Commission.

L. **State**
The Public Utility Commission of Oregon.

M. **State-Initiated**
Actions taken by the State to implement individual load curtailment plans within its jurisdiction.

N. **Threshold Consumption Level**
The maximum amount of Electricity that a Customer can use during mandatory load curtailment without being subject to penalties under this Plan.

O. **Utility Coordinator**
The Director of the Northwest Power Pool.

P. **Utility Curtailment Reports**
Report(s) summarizing Curtailment data, such reports are to be submitted monthly to the Commission and the Utility Coordinator.

Q. **Weather-Normalization**
The procedure used to reflect the impact of weather on load levels. Sometimes referred to as weather-adjustment.

3. Curtailment Stages

State curtailment directives apply to all retail loads served within the State of Oregon. Under the Plan, Curtailment is requested or ordered as a percentage of historical, weather-normalized (Base Billing Period) Electricity consumption. The curtailment stages are associated with increasing Electricity deficits. The five stages of Curtailment are:

RULE N (Continued)

Curtailment Stages (Continued)

Stage	Nature	Curtailment Requirement	Curtailment Type
Stage 1	Voluntary	No Specified %	Uniform Among All Regional Customers
Stage 2	Voluntary	5% or Greater	Uniform Among All Regional Customers
Stage 3	Mandatory	5 to 15%	Uniform Among All Regional Customers
Stage 4	Mandatory	15% 15% or Greater 15% or Greater	Residential Customers General Use Customers Major Use Customers
Stage 5	Mandatory	% Associated with Stage 4 Plus Additional Curtailment	Continued Customer Curtailment Plus Utility Action, Including Plant Closures and Possible Blackouts

4. Initiation of Load Curtailment

Curtailment will be initiated when directed by State authorities. However, nothing precludes the Company from requesting voluntary load reduction at any time.

5. Administration of State-Initiated Curtailment

A. **Stage-By-Stage Utility Administrative Obligations**

Upon notice from the State to initiate load curtailment, the Company will immediately begin complying with the directives of this Plan. All requirements for lower-level stages continue to apply to higher-level stages. Throughout a period of Curtailment, the Company will provide Electricity Service Suppliers (ESSs), Customers and the general public with as much useful information as can reasonably be supplied. The requirements specified below represent the minimum actions to be taken.

RULE N (Continued)

Stage-By-Stage Utility Administrative Obligations (Continued)

1) **Stage 1**
The Company will begin, or continue if it has already begun, providing Curtailment information to ESSs, Customers and the general public. The Company will also assist the State, as appropriate, in briefing the media about the shortage.
2) **Stage 2**
In Stage 2, the Company will:
   a) Notify ESSs, Customers and the general public of the percentage level of voluntary curtailment stemming from State Action;
   b) Provide Curtailment tips to ESSs, Customers and the general public;
   c) Answer Customer questions about Curtailment;
   d) Provide Curtailment reports to the State and the Utility Coordinator; and
   e) Provide more detailed information to the media than provided in Stage 1.
3) **Stage 3**
In Stage 3, the Company will:
   a) Notify ESSs, Customers and the general public of the percentage level of State-ordered mandatory Curtailment;
   b) Calculate weather-normalized Base Billing Period data and Curtailment Targets for all Customers who will be audited in the current billing period;
   c) Provide Curtailment Targets to ESSs and all Customers who request such data for their own accounts;
   d) Provide audited Customers with information about how to apply for exemption and adjustment of Base Year data;
   e) Process requests for exemption and Base Year data adjustments from those Customers selected for audit who would otherwise be subject to penalties; and
   f) Implement the penalties aspect of the Plan.
4) **Stage 4**
In Stage 4, the Company will notify ESSs, Customers and the general public of any applicable changes in State-initiated mandatory curtailment.
5) **Stage 5**
In Stage 5, the Company will collaborate with the State to develop and implement the most effective methods to secure the required Electricity Curtailment while minimizing, to the extent possible, any economic and human hardships of the last stage of load curtailment.

B. **<u>Suggested Curtailment Actions</u>**

Information will be disseminated to Customers regarding actions that they can take to reduce their Electricity consumption. The Company will work with the State to develop this material. The recommendations will be based on the actions described in Appendix C of the Regional Plan.

RULE N (Continued)

6. **Base Year Data and Curtailment Targets**

   A. **Identification of the Base Year**

   The Base Year for a shortage will be established by the State. Base Year and Base Billing Period data shall be weather-normalized.

   B. **Estimating Base Billing Period Data for Customers for Whom No Base Billing Period Data Exists**

   Base Billing Period data must be obtained or developed for any Customer who is audited under this Plan. Although the Company has the option of excluding residential and General Use Customers without actual Base Billing Period data from the random sample of audited Customers, Base Billing Period data will be estimated for any audited Customer for whom actual data does not exist or is found to be inaccurate.

   C. **Communicating Curtailment Target Information to Customers**

   During mandatory Curtailment, retrospective, current billing period, and forthcoming billing period Curtailment Target information will be provided to any Customer who requests such information. Retrospective Curtailment Target information will be provided to any audited Customer who will be issued a warning or penalty. At its option, the Company may provide Curtailment Target information to other Customers or Customer classes as well.

7. **Auditing Customers for Compliance with State Orders for Mandatory Load Curtailment During Curtailment Stages 3-5**

   A. Each billing period, at least 1% of residential users, 5% of General Use Customers, and 100% of Major Use Customers (including those Major Use Customers with estimated Base Billing Period data) plus any Customers penalized in the previous billing period will be audited. The number of Customers exempted or excluded from audit will not affect the sample size.

   B. New compliance samples shall be drawn each month. Customers penalized under this Plan shall continue to be audited until their Energy use falls below the Threshold Consumption Level. Once their Energy use falls below that level, they will be audited again only if selected by random sample.

RULE N (Continued)

Auditing Customers for Compliance with State Orders (Continued)

C. Unless the Company is auditing 100% of its residential users and General Use Customers, all such Customers selected for audit shall be chosen on a random sample basis, except that the following Customers are to be excluded: (a) Customers granted an exemption under this Plan; and (b) Customers with an estimated power bill in the current billing period. At its option the Company may also choose to exclude Customers with estimated Base Billing Period data, if the State does not require their inclusion in the pool of Customers subject to audit.

8. Penalties for Noncompliance

A. **Nature of Penalties**

The following penalties will be assessed under this Plan to Excess Power Consumption as defined below:

Violation	Penalty
First Bimonthly Violation	10¢ per kWh of Excess Use
Second Bimonthly Violation	20¢ per kWh of Excess Use
Third Bimonthly Violation	40¢ per kWh of Excess Use
Fourth Bimonthly Violation	1 Day Disconnection Plus 40¢ per kWh of Excess Use
Fifth Bimonthly Violation	2 Days Disconnection Plus 40¢ per kWh of Excess Use
Sixth and all Subsequent Violations	Penalties are Determined by the State; Civil Penalties or Other Corrective Actions would be possibilities.

The penalty for violators who are billed every two months will escalate on every power bill in which they are subject to penalty. Customers billed on a monthly basis will be assessed the same penalty on two successive occasions before incurring the next higher level penalty. During any continuous period of curtailment, assessed penalties remain on the record for the purposes of administration of subsequent penalties, even if there has been an intervening period of compliance.
Standard disconnect criteria and procedures will be used whenever disconnecting Customers in accordance with this Plan. Health, safety, and welfare considerations will be taken into account, and Customers will be billed for normal disconnect and reconnect charges.

RULE N (Continued)

Nature of Penalties (Continued)

B. **Calculation of Financial Penalties**

Financial penalties will be calculated by multiplying the Customer's Excess Electricity Consumption each billing period by the appropriate penalty level identified above.

1) **Threshold Consumption Level**

The Threshold Consumption Level assigned to each Customer class is identified as:

a) Residential Customers, 10% Above Curtailment Target.
b) General Use Customers, 10% Above Curtailment Target.
c) Major Use Customers, 2% Above Curtailment Target.

These values may be changed by the State so as to effect better compliance with the curtailment order.

2) **Excess Power Consumption Calculation**

Penalties will not be assessed if a Customer's load (either actual load or weather-normalized load) is equal to, or less than, the Threshold Consumption Level. Excess Power Consumption is the lower of the following two values for each sampled load subject to penalty: (a) (Actual Load) minus (Curtailment Target) or (b) (Weather-Normalized Load) minus (Curtailment Target).

3) **Assessment of Penalties**

Penalties Vs Warnings. Customers will be assessed penalties only if they have Excess Electricity Consumption and if they are to be penalized based on the penalty assessment procedures described below. Any sampled Customer who is not penalized and whose use exceeds the Curtailment Target will receive a warning.

C. **Penalty Assessment Procedures**

Sample at the mandated minimum percentages for each section as specified in this Plan [1%-5%-100%] (or as otherwise specified by the State) and assess penalties on all Customers with Excess Power Consumption. At its option, the Company may sample at higher percentages of Customers than the minimum required by Section 7 above and may choose among the following penalty assessment options:

1) **Option (1)**

Assess penalties on all sampled Customers with Excess Power Consumption (this methodology must be used for Major Use Customers even if the utility chooses Option (2), below, for its other Customer sectors); or

RULE N (Continued)

Penalty Assessment Procedures (Continued)

2) **Option (2)**
Develop a ratio of the minimum percentage sample size to the actual percentage sampled for the Residential and/or General Use Customer sectors. Multiply the resulting percentages by the total number of violators in each respective Customer sector to determine the minimum number of penalties that must be assessed in each sector. Calculate the percentage violation for each individual Customer that has been sampled (Excess Power Consumption divided by Curtailment Target) and apply penalties to the worst offenders in the overall sample based on their percentage Excess Power Consumption. Also penalize all Customers who were penalized in the previous billing period and who still have Excess Power Consumption.

D. **Billing Customers for Penalties**

The penalty on the power bill may be described as State-mandated and shall include any State-provided material describing the penalty aspect of the Plan as a bill stuffer in the bills of penalized Customers. If the Customer is receiving an ESS Consolidated Bill, the ESS will bill the Customer for any penalties incurred by that Customer. The bills shall include any Commission-provided material describing the penalty aspect of the Plan, such as a bill stuffer. When the Company is billing the Customer, the bills shall note that failure to pay penalties will result in service disconnection in accordance with standard disconnect criteria and procedures.

E. **Treatment of Penalties Pending Adjustment / Exemption Determinations**

A Customer that has applied for adjustment of Base Billing Period data and/or exemption from mandatory Curtailment may request a stay of enforcement of the penalty aspect of the Plan pending a final decision regarding its request. Any Customer who has been granted such a stay will be subject to retroactive penalties as applicable if the request is ultimately denied.

F. **Use of Funds Collected Under the Penalty Provisions of the Plan**

Funds collected under the State-ordered penalty provisions of this Plan shall be set aside in a separate account. The ultimate disposition of these funds will be determined by the Commission.

RULE N (Continued)

9. Exemptions and Adjustments

A. **Customer Application for Exemption/Adjustment**

Customers will be informed of how to apply for exemption from Plan requirements or adjustments of Base Billing Period data. At its option, the Company may elect to process exemptions and adjustments only for audited Customers. Customers seeking an exemption or adjustment shall apply first to the Company and then, if dissatisfied with that outcome, to the Commission.

At its option, the Company may provide for a credit against future curtailment for a Customer who has already accomplished a reduction in Demand for the utility's service by installing an alternative Energy device or by weatherization or other installed conservation measures equivalent to the proposed level of curtailment. Where the level of curtailment exceeds the Demand reduction produced by the conservation measures or installed alternative Energy device of the Customer, the Company may provide for credit against the level of curtailment ordered to the extent of the Demand reduction produced by the conservation measure or alternate Energy device.

B. **Granting Customer Requests for Exemption from Mandatory Curtailment**

No automatic Customer exemptions will be granted under mandatory State-initiated load curtailment. Exempted Customers should be informed that exemption may not protect them from Stage 5 blackouts.

1) **Critical Load Customers**
Critical Load Customers may be exempted once the Customers have demonstrated to the Company that they have eliminated all nonessential Energy use and are using any reliable, cost-effective backup Energy resources.

2) **Other Customers**
Exemptions for Customers not qualifying as Critical Load Customers under the Plan will be evaluated based on whether Curtailment would result in unreasonable exposure to health or safety hazards, seriously impair the welfare of the affected Customer, cause extreme economic hardship relative to the amount of Energy saved, or produce counterproductive results.

C. **Utility Record Keeping Relative to Customer Exemptions**

Records regarding exemption determinations will be made available to the Commission upon request.

RULE N (Concluded)

10. Measurement of the Amount of Curtailment Achieved and Determination of Compliance

At all times during State-initiated regional load curtailment, the Commission and the Utility Coordinator will be provided with consumption and savings data on a monthly basis in the form specified in Appendix D of the Regional Plan. To the extent that circumstances at the time of actual load curtailment dictate the need for additional data or more frequent data submittal, a best effort to comply with the Commission request will be made.

11. Special Arrangements

A. **Use of Customer-Owned Generation Facilities**

Consistent with the need for safety and system protection, Customers having their own generation facilities or access to electricity from non-utility power sources may choose to use Energy from those other sources to supplement their curtailed power purchases from their electric utility under any protracted regional shortage situation.

B. **Curtailment Scheduling**

During periods of mandatory Curtailment, a Customer is obligated to provide the requisite amount of curtailment within each billing period. Within that period, and subject to equipment limitations and the Company's rules on load fluctuations, Customers are free to schedule their curtailment so as to minimize the economic cost, hardship or inconvenience they experience as a result of the mandatory curtailment requirement.

C. **Related Curtailment Information**

The Regional Electric Energy Curtailment Plan is included, by reference. That plan contains additional information on curtailment administration.

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2024

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast Dec22E24)	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ Sch. 125, 122, and 146	TOTAL ELECTRIC BILLS PROPOSED w/ Sch. 125, 122, and 146	Change AMOUNT	Change PCT.	
Residential	7	827,209	7,901,146	$1,219,155,468	$1,410,889,508	$191,734,040	15.7%	
Employee Discount				($1,310,093)	($1,512,228)	($202,135)		
Subtotal				$1,217,845,375	$1,409,377,281	$191,531,906	15.7%	
Outdoor Area Lighting	15	0	13,335	$3,703,863	$4,043,238	$339,375	9.2%	
General Service <30 kW	32	96,878	1,545,473	$217,941,322	$252,517,108	$34,575,786	15.9%	
Opt. Time-of-Day G.S. >30 kW	38	354	27,293	$4,118,114	$4,579,861	$461,746	11.2%	
Irrig. & Drain. Pump. < 30 kW	47	2,818	20,562	$4,803,347	$5,026,953	$223,607	4.7%	
Irrig. & Drain. Pump. > 30 kW	49	1,282	61,295	$11,163,504	$12,484,264	$1,320,760	11.8%	
General Service 31-200 kW	83	11,739	2,877,497	$320,934,759	$361,173,976	$40,239,217	12.5%	
General Service 201-4,000 kW								
Secondary	85-S	1,244	2,054,657	$192,277,813	$219,419,656	$27,141,843	14.1%	13.7%
Primary	85-P	168	694,191	$57,330,434	$64,413,739	$7,083,305	12.4%	
Schedule 89 > 4 MW								
Primary	89-P	20	1,240,557	$94,098,510	$103,412,355	$9,313,846	9.9%	
Subtransmission	89-T/75-T	4	55,961	$5,054,195	$5,549,631	$495,436	9.8%	9.9%
Schedule 90	90-P	6	3,200,967	$222,404,726	$246,303,160	$23,898,434	10.7%	
Street & Highway Lighting	91/95	186	39,857	$13,008,688	$13,270,984	$262,296	2.0%	
Traffic Signals	92	16	2,723	$222,932	$252,831	$29,899	13.4%	
COS TOTALS		941,923	19,735,515	$2,364,907,583	$2,701,825,038	$336,917,455	14.2%	
Direct Access Service 201-4,000 kW								
Secondary	485-S	214	427,305	$8,551,218	$9,240,008	$688,791	8.1%	
Primary	485-P	51	314,583	$5,436,637	$5,519,815	$83,178	1.5%	
Direct Access Service > 4 MW								
Primary	489-P	20	1,149,945	$9,695,127	$8,852,933	($842,194)	-8.7%	
Subtransmission	489-T	3	277,803	$1,597,932	$1,322,170	($275,762)	-17.3%	
New Load Direct Access Service > 10MW								
Primary	689-P	3	178,318	$2,405,552	$1,799,451	($606,100)	-25.2%	
DIRECT ACCESS TOTALS		290	2,347,955	27,686,465	26,734,378	($952,088)		
COS AND DA CYCLE TOTALS		942,213	22,083,470	$2,392,594,048	$2,728,559,415	$335,965,367	14.0%	
				($0)	($0)			

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7

kWh	Net Monthly Bill: Current Prices	Net Monthly Bill: Proposed Prices	Percent Difference
50	$20.56	$23.86	16.1%
100	$27.79	$32.32	16.3%
200	$42.19	$49.26	16.8%
250	$49.41	$57.74	16.9%
300	$56.62	$66.20	16.9%
400	$71.03	$83.13	17.0%
500	$85.46	$100.08	17.1%
600	$99.85	$116.98	17.2%
700	$114.28	$133.93	17.2%
780	$125.79	$147.46	17.2%
800	$128.69	$150.86	17.2%
850	$135.89	$159.32	17.2%
900	$143.11	$167.81	17.3%
1,000	$157.52	$184.73	17.3%
1,100	$172.31	$201.66	17.0%
1,200	$187.08	$218.59	16.8%
1,300	$201.87	$235.53	16.7%
1,400	$216.65	$252.47	16.5%
1,500	$231.45	$269.42	16.4%
1,600	$246.20	$286.32	16.3%
1,700	$261.00	$303.27	16.2%
1,800	$275.77	$320.19	16.1%
2,000	$305.33	$354.06	16.0%
2,300	$349.68	$404.86	15.8%
2,750	$416.20	$481.08	15.6%
3,000	$453.13	$523.38	15.5%
3,500	$527.06	$608.07	15.4%
4,000	$600.94	$692.71	15.3%
4,500	$674.87	$777.40	15.2%
5,000	$748.75	$862.04	15.1%
7,500	$1,118.30	$1,285.38	14.9%
10,000	$1,487.80	$1,708.67	14.8%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
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	$92.54	$104.09	12.5%	$89.11	$100.66	13.0%
600	$106.96	$120.40	12.6%	$102.84	$116.28	13.1%
700	$121.41	$136.75	12.6%	$116.61	$131.95	13.2%
800	$135.85	$153.12	12.7%	$130.36	$147.63	13.2%
900	$150.30	$169.45	12.7%	$144.13	$163.28	13.3%
1,000	$164.73	$185.80	12.8%	$157.87	$178.93	13.3%
1,500	$236.97	$267.55	12.9%	$226.68	$257.26	13.5%
1,750	$273.09	$308.42	12.9%	$261.08	$296.41	13.5%
2,000	$309.17	$349.26	13.0%	$295.45	$335.54	13.6%
2,500	$381.41	$431.02	13.0%	$364.25	$413.87	13.6%
3,500	$525.84	$594.48	13.1%	$501.82	$570.47	13.7%
4,000	$598.04	$676.19	13.1%	$570.59	$648.75	13.7%
4,500	$670.27	$757.95	13.1%	$639.40	$727.07	13.7%
5,000	$742.47	$839.66	13.1%	$708.16	$805.35	13.7%
6,000	$848.05	$973.31	14.8%	$806.88	$932.14	15.5%
7,000	$953.63	$1,106.97	16.1%	$905.60	$1,058.94	16.9%
8,000	$1,059.21	$1,240.62	17.1%	$1,004.32	$1,185.73	18.1%
9,000	$1,164.79	$1,374.28	18.0%	$1,103.04	$1,312.52	19.0%
10,000	$1,270.37	$1,507.93	18.7%	$1,201.76	$1,439.32	19.8%
14,000	$1,692.69	$2,042.55	20.7%	$1,596.63	$1,946.49	21.9%
15,000	$1,798.27	$2,176.20	21.0%	$1,695.35	$2,073.28	22.3%
20,000	$2,326.17	$2,844.48	22.3%	$2,188.94	$2,707.25	23.7%
21,900	$2,526.78	$3,098.43	22.6%	$2,376.52	$2,948.17	24.1%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
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	$101.67	$113.22	11.4%	$98.24	$109.79	11.8%
600	$116.10	$129.53	11.6%	$111.97	$125.41	12.0%
700	$130.55	$145.89	11.8%	$125.75	$141.08	12.2%
800	$144.98	$162.26	11.9%	$139.49	$156.77	12.4%
900	$159.44	$178.59	12.0%	$153.26	$172.42	12.5%
1,000	$173.87	$194.93	12.1%	$167.01	$188.07	12.6%
1,500	$246.11	$276.69	12.4%	$235.81	$266.40	13.0%
1,750	$282.22	$317.56	12.5%	$270.22	$305.55	13.1%
2,000	$318.30	$358.40	12.6%	$304.58	$344.67	13.2%
2,500	$390.54	$440.15	12.7%	$373.39	$423.00	13.3%
3,500	$534.97	$603.62	12.8%	$510.96	$579.60	13.4%
4,000	$607.17	$685.33	12.9%	$579.73	$657.88	13.5%
4,500	$679.41	$767.08	12.9%	$648.53	$736.21	13.5%
5,000	$751.61	$848.79	12.9%	$717.30	$814.48	13.5%
6,000	$857.18	$982.45	14.6%	$816.02	$941.28	15.4%
7,000	$962.76	$1,116.10	15.9%	$914.73	$1,068.07	16.8%
8,000	$1,068.34	$1,249.76	17.0%	$1,013.45	$1,194.86	17.9%
9,000	$1,173.92	$1,383.41	17.8%	$1,112.17	$1,321.66	18.8%
10,000	$1,279.50	$1,517.06	18.6%	$1,210.89	$1,448.45	19.6%
14,000	$1,701.82	$2,051.68	20.6%	$1,605.76	$1,955.62	21.8%
15,000	$1,807.40	$2,185.34	20.9%	$1,704.48	$2,082.42	22.2%
20,000	$2,335.30	$2,853.61	22.2%	$2,198.07	$2,716.38	23.6%
21,900	$2,535.92	$3,107.56	22.5%	$2,385.66	$2,957.30	24.0%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
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	$49.22	$51.74	5.1%	$48.87	$51.39	5.2%
10	100	$60.89	$63.87	4.9%	$60.20	$63.18	5.0%
10	500	$154.24	$161.04	4.4%	$150.81	$157.61	4.5%
10	1,000	$260.71	$272.29	4.4%	$253.85	$265.43	4.6%
10	2,000	$473.72	$494.85	4.5%	$459.99	$481.13	4.6%
10	5,000	$1,112.74	$1,162.52	4.5%	$1,078.43	$1,128.22	4.6%
20	100	$60.89	$63.87	4.9%	$60.20	$63.18	5.0%
20	200	$84.19	$88.14	4.7%	$82.82	$86.77	4.8%
20	500	$154.24	$161.04	4.4%	$150.81	$157.61	4.5%
20	1,000	$270.86	$282.44	4.3%	$264.00	$275.58	4.4%
20	2,000	$483.87	$505.00	4.4%	$470.14	$491.28	4.5%
20	5,000	$1,122.89	$1,172.67	4.4%	$1,088.58	$1,138.37	4.6%
20	8,000	$1,761.91	$1,840.34	4.5%	$1,707.01	$1,785.45	4.6%
30	150	$72.54	$76.01	4.8%	$71.51	$74.99	4.9%
30	500	$154.24	$161.04	4.4%	$150.81	$157.61	4.5%
30	1,000	$270.86	$282.44	4.3%	$264.00	$275.58	4.4%
30	3,000	$707.02	$737.71	4.3%	$686.44	$717.12	4.5%
30	5,000	$1,133.04	$1,182.82	4.4%	$1,098.73	$1,148.52	4.5%
30	8,000	$1,772.06	$1,850.49	4.4%	$1,717.16	$1,795.60	4.6%
30	10,000	$2,198.07	$2,295.61	4.4%	$2,129.45	$2,227.00	4.6%
30	15,000	$3,263.10	$3,408.40	4.5%	$3,160.18	$3,305.48	4.6%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
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	$1,010.04	$1,124.56	11.3%	$974.98	$1,089.50	11.7%
40%	35	10,220	$1,938.88	$2,162.83	11.6%	$1,868.75	$2,092.70	12.0%
60%	35	15,330	$2,867.69	$3,201.08	11.6%	$2,762.50	$3,095.90	12.1%
80%	35	20,440	$3,796.50	$4,239.35	11.7%	$3,656.26	$4,099.11	12.1%
20%	50	7,300	$1,423.36	$1,584.77	11.3%	$1,373.27	$1,534.68	11.8%
40%	50	14,600	$2,750.22	$3,067.96	11.6%	$2,650.04	$2,967.78	12.0%
60%	50	21,900	$4,077.14	$4,551.25	11.6%	$3,926.88	$4,400.99	12.1%
80%	50	29,200	$5,404.01	$6,034.45	11.7%	$5,203.66	$5,834.10	12.1%
20%	70	10,220	$1,974.40	$2,198.34	11.3%	$1,904.28	$2,128.22	11.8%
40%	70	20,440	$3,832.03	$4,274.87	11.6%	$3,691.79	$4,134.63	12.0%
60%	70	30,660	$5,689.71	$6,351.41	11.6%	$5,479.34	$6,141.05	12.1%
80%	70	40,880	$7,547.35	$8,427.93	11.7%	$7,266.86	$8,147.43	12.1%
20%	100	14,600	$2,800.97	$3,118.71	11.3%	$2,700.79	$3,018.53	11.8%
40%	100	29,200	$5,454.76	$6,085.20	11.6%	$5,254.41	$5,884.85	12.0%
60%	100	43,800	$8,108.58	$9,051.70	11.6%	$7,808.05	$8,751.16	12.1%
80%	100	58,400	$10,762.37	$12,018.18	11.7%	$10,361.67	$11,617.48	12.1%
20%	200	29,200	$5,556.26	$6,186.70	11.3%	$5,355.91	$5,986.35	11.8%
40%	200	58,400	$10,863.87	$12,119.68	11.6%	$10,463.17	$11,718.98	12.0%
60%	200	87,600	$16,171.46	$18,052.61	11.6%	$15,570.40	$17,451.55	12.1%
80%	200	116,800	$21,479.07	$23,985.59	11.7%	$20,677.66	$23,184.18	12.1%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 38, 3-phase Service
Bill comparison assumes 51% on peak and 49% off peak energy consumption

	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	$193.04	$214.65	11.2%	$186.18	$207.79	11.6%
3,000	$518.23	$572.91	10.6%	$497.65	$552.32	11.0%
5,000	$843.42	$931.17	10.4%	$809.11	$896.86	10.8%
7,000	$1,168.61	$1,289.42	10.3%	$1,120.58	$1,241.39	10.8%
10,000	$1,656.39	$1,826.81	10.3%	$1,587.77	$1,758.19	10.7%
13,000	$2,144.17	$2,364.19	10.3%	$2,054.97	$2,274.99	10.7%
14,000	$2,306.76	$2,543.32	10.3%	$2,210.70	$2,447.26	10.7%
16,000	$2,631.95	$2,901.57	10.2%	$2,522.17	$2,791.79	10.7%
21,000	$3,444.92	$3,797.21	10.2%	$3,300.83	$3,653.12	10.7%
25,000	$4,095.29	$4,513.73	10.2%	$3,923.76	$4,342.19	10.7%
30,000	$4,908.26	$5,409.37	10.2%	$4,702.42	$5,203.52	10.7%
35,000	$5,721.23	$6,305.01	10.2%	$5,481.08	$6,064.86	10.7%
40,000	$6,534.20	$7,200.65	10.2%	$6,259.74	$6,926.19	10.6%
45,000	$7,347.16	$8,096.29	10.2%	$7,038.40	$7,787.52	10.6%
50,000	$8,160.14	$8,991.94	10.2%	$7,817.07	$8,648.87	10.6%
75,000	$12,224.97	$13,470.13	10.2%	$11,710.37	$12,955.52	10.6%
100,000	$16,289.82	$17,948.33	10.2%	$15,603.68	$17,262.19	10.6%
150,000	$24,419.51	$26,904.74	10.2%	$23,390.30	$25,875.53	10.6%
200,000	$32,549.18	$35,861.13	10.2%	$31,176.90	$34,488.85	10.6%
300,000	$48,808.55	$53,773.93	10.2%	$46,750.13	$51,715.51	10.6%
400,000	$65,067.91	$71,686.73	10.2%	$62,323.35	$68,942.17	10.6%
500,000	$81,307.28	$89,579.53	10.2%	$77,876.58	$86,148.83	10.6%
750,000	$116,141.50	$128,547.34	10.7%	$110,995.45	$123,401.29	11.2%
1,000,000	$154,678.50	$171,217.93	10.7%	$147,817.10	$164,356.53	11.2%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service.
Bill comparison assumes 63% on peak and 37% off peak energy consumption

			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	$936.35	$1,079.17	15.3%	$891.27	$1,034.09	16.0%
30%	50	10,950	$1,528.06	$1,762.71	15.4%	$1,452.93	$1,687.58	16.2%
30%	75	16,425	$2,267.71	$2,617.16	15.4%	$2,155.02	$2,504.46	16.2%
30%	63	21,250	$2,485.42	$2,745.34	10.5%	$2,339.61	$2,599.53	11.1%
30%	135	29,565	$4,042.95	$4,667.85	15.5%	$3,840.09	$4,464.99	16.3%
30%	175	38,325	$5,226.42	$6,034.98	15.5%	$4,963.45	$5,772.01	16.3%
30%	200	43,800	$5,966.08	$6,889.44	15.5%	$5,665.55	$6,588.91	16.3%
50%	30	10,950	$1,272.89	$1,395.48	9.6%	$1,197.76	$1,320.35	10.2%
50%	50	18,250	$2,089.03	$2,289.96	9.6%	$1,963.81	$2,164.74	10.2%
50%	63	21,250	$2,485.42	$2,745.34	10.5%	$2,339.61	$2,599.53	11.1%
50%	100	36,500	$4,129.33	$4,526.11	9.6%	$3,878.89	$4,275.67	10.2%
50%	135	49,275	$5,557.51	$6,091.39	9.6%	$5,219.42	$5,753.30	10.2%
50%	175	63,875	$7,189.74	$7,880.31	9.6%	$6,751.46	$7,442.03	10.2%
50%	200	73,000	$8,209.87	$8,998.37	9.6%	$7,708.99	$8,497.49	10.2%
70%	30	15,330	$1,609.45	$1,711.81	6.4%	$1,504.26	$1,606.63	6.8%
70%	50	25,550	$2,649.96	$2,817.19	6.3%	$2,474.65	$2,641.88	6.8%
70%	75	38,325	$3,950.57	$4,198.84	6.3%	$3,687.60	$3,935.88	6.7%
70%	100	51,100	$5,251.17	$5,580.53	6.3%	$4,900.55	$5,229.91	6.7%
70%	135	68,985	$7,072.06	$7,514.92	6.3%	$6,598.73	$7,041.58	6.7%
70%	175	89,425	$9,153.00	$9,725.59	6.3%	$8,539.42	$9,112.01	6.7%
70%	200	102,200	$10,453.66	$11,107.31	6.3%	$9,752.43	$10,406.08	6.7%
90%	30	19,710	$1,946.02	$2,028.16	4.2%	$1,810.79	$1,892.92	4.5%
90%	50	32,850	$3,210.91	$3,344.42	4.2%	$2,985.51	$3,119.02	4.5%
90%	75	49,275	$4,792.00	$4,989.71	4.1%	$4,453.90	$4,651.62	4.4%
90%	100	65,700	$6,373.08	$6,635.01	4.1%	$5,922.29	$6,184.22	4.4%
90%	135	88,695	$8,586.59	$8,938.42	4.1%	$7,978.02	$8,329.85	4.4%
90%	175	114,975	$11,116.33	$11,570.91	4.1%	$10,327.44	$10,782.02	4.4%
90%	200	131,400	$12,697.43	$13,216.22	4.1%	$11,795.84	$12,314.64	4.4%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Secondary, 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
30%	200	43,800	$6,080.61	$7,164.84	17.8%
30%	300	65,700	$8,588.05	$10,209.36	18.9%
30%	500	109,500	$13,602.93	$16,298.34	19.8%
30%	700	153,300	$18,617.75	$22,387.27	20.2%
30%	800	175,200	$21,125.19	$25,431.75	20.4%
30%	900	197,100	$23,632.61	$28,476.22	20.5%
30%	1,000	219,000	$26,140.03	$31,520.70	20.6%
30%	1,500	328,500	$38,677.22	$46,743.14	20.9%
30%	2,000	438,000	$51,214.32	$61,965.50	21.0%
30%	4,000	876,000	$96,532.03	$118,024.25	22.3%
50%	200	73,000	$8,009.61	$8,970.87	12.0%
50%	300	109,500	$11,481.58	$12,918.39	12.5%
50%	500	182,500	$18,425.44	$20,813.35	13.0%
50%	700	255,500	$25,369.31	$28,708.32	13.2%
50%	800	292,000	$28,841.20	$32,655.77	13.2%
50%	900	328,500	$32,313.17	$36,603.29	13.3%
50%	1,000	365,000	$35,785.06	$40,550.74	13.3%
50%	1,500	547,500	$53,075.35	$60,218.79	13.5%
50%	2,000	730,000	$70,245.16	$79,766.37	13.6%
50%	4,000	1,460,000	$131,558.22	$150,590.49	14.5%
70%	200	102,200	$9,938.62	$10,776.89	8.4%
70%	300	153,300	$14,375.05	$15,627.37	8.7%
70%	500	255,500	$23,247.96	$25,328.37	8.9%
70%	700	357,700	$32,120.80	$35,029.32	9.1%
70%	800	408,800	$36,557.22	$39,879.78	9.1%
70%	900	459,900	$40,993.67	$44,730.30	9.1%
70%	1,000	511,000	$45,398.64	$49,549.33	9.1%
70%	1,500	766,500	$63,447.78	$69,668.74	9.8%
70%	2,000	1,022,000	$84,075.08	$92,366.31	9.9%
70%	4,000	2,044,000	$166,584.41	$183,156.72	9.9%
90%	200	131,400	$11,867.63	$12,582.88	6.0%
90%	300	197,100	$17,268.56	$18,336.37	6.2%
90%	500	328,500	$28,070.47	$29,843.39	6.3%
90%	700	459,900	$38,872.32	$41,350.35	6.4%
90%	800	525,600	$44,226.61	$47,057.20	6.4%
90%	900	591,300	$49,559.23	$52,742.36	6.4%
90%	1,000	657,000	$54,891.82	$58,427.52	6.4%
90%	1,500	985,500	$76,582.60	$81,881.08	6.9%
90%	2,000	1,314,000	$101,588.17	$108,649.43	7.0%
90%	4,000	2,628,000	$201,610.60	$215,722.95	7.0%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, 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
30%	200	43,800	$5,980.10	$6,973.27	16.6%
30%	300	65,700	$8,457.61	$9,982.90	18.0%
30%	500	109,500	$13,412.60	$16,002.11	19.3%
30%	700	153,300	$18,367.51	$22,021.25	19.9%
30%	800	175,200	$20,845.02	$25,030.85	20.1%
30%	900	197,100	$23,322.47	$28,040.42	20.2%
30%	1,000	219,000	$25,799.97	$31,050.02	20.3%
30%	1,500	328,500	$38,187.43	$46,098.03	20.7%
30%	2,000	438,000	$50,574.79	$61,145.95	20.9%
30%	4,000	876,000	$95,179.69	$116,393.07	22.3%
50%	200	73,000	$7,880.02	$8,758.49	11.1%
50%	300	109,500	$11,307.49	$12,660.73	12.0%
50%	500	182,500	$18,162.37	$20,465.12	12.7%
50%	700	255,500	$25,017.23	$28,269.50	13.0%
50%	800	292,000	$28,444.61	$32,171.65	13.1%
50%	900	328,500	$31,872.10	$36,073.89	13.2%
50%	1,000	365,000	$35,299.48	$39,976.04	13.2%
50%	1,500	547,500	$52,367.30	$59,417.66	13.5%
50%	2,000	730,000	$69,314.61	$78,738.78	13.6%
50%	4,000	1,460,000	$129,547.91	$148,467.31	14.6%
70%	200	102,200	$9,779.92	$10,543.71	7.8%
70%	300	153,300	$14,157.29	$15,338.49	8.3%
70%	500	255,500	$22,912.12	$24,928.12	8.8%
70%	700	357,700	$31,666.85	$34,517.68	9.0%
70%	800	408,800	$36,044.21	$39,312.45	9.1%
70%	900	459,900	$40,421.64	$44,107.29	9.1%
70%	1,000	511,000	$44,767.55	$48,870.62	9.2%
70%	1,500	766,500	$62,421.80	$68,611.93	9.9%
70%	2,000	1,022,000	$82,720.64	$90,997.83	10.0%
70%	4,000	2,044,000	$163,916.14	$180,541.55	10.1%
90%	200	131,400	$11,679.82	$12,328.89	5.6%
90%	300	197,100	$17,007.14	$18,016.28	5.9%
90%	500	328,500	$27,661.88	$29,391.13	6.3%
90%	700	459,900	$38,316.53	$40,765.91	6.4%
90%	800	525,600	$43,597.21	$46,406.65	6.4%
90%	900	591,300	$48,856.20	$52,025.72	6.5%
90%	1,000	657,000	$54,115.22	$57,644.79	6.5%
90%	1,500	985,500	$75,309.89	$80,639.77	7.1%
90%	2,000	1,314,000	$99,904.76	$107,034.95	7.1%
90%	4,000	2,628,000	$198,284.36	$212,615.80	7.2%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Secondary.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	**kW**	**kWh**	**Current Prices**	**Proposed Prices**	**Percent Difference**
30%	4,000	876,000	$87,792.56	$96,467.36	9.9%
30%	7,500	1,642,500	$158,374.10	$174,941.32	10.5%
30%	10,000	2,190,000	$208,789.47	$230,994.12	10.6%
30%	15,000	3,285,000	$309,620.23	$343,099.75	10.8%
30%	20,000	4,380,000	$406,397.89	$451,152.29	11.0%
50%	4,000	1,460,000	$130,038.56	$141,884.63	9.1%
50%	7,500	2,737,500	$237,585.36	$260,098.70	9.5%
50%	10,000	3,650,000	$314,404.48	$344,537.30	9.6%
50%	15,000	5,475,000	$462,722.63	$508,094.40	9.8%
50%	20,000	7,300,000	$614,249.19	$674,859.91	9.9%
70%	4,000	2,044,000	$172,284.57	$187,301.90	8.7%
70%	7,500	3,832,500	$316,796.62	$345,256.09	9.0%
70%	10,000	5,110,000	$415,121.71	$453,182.69	9.2%
70%	15,000	7,665,000	$618,611.10	$675,875.11	9.3%
70%	20,000	10,220,000	$822,100.48	$898,567.53	9.3%
90%	4,000	2,628,000	$214,530.57	$232,719.17	8.5%
90%	7,500	4,927,500	$391,321.27	$425,726.86	8.8%
90%	10,000	6,570,000	$519,047.36	$565,036.50	8.9%
90%	15,000	9,855,000	$774,499.57	$843,655.83	8.9%
90%	20,000	13,140,000	$1,029,951.77	$1,122,275.16	9.0%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill: Current Prices	Net Monthly Bill: Proposed Prices	Percent Difference
30%	4,000	876,000	$85,021.81	$95,367.75	12.2%
30%	7,500	1,642,500	$154,644.35	$172,923.96	11.8%
30%	10,000	2,190,000	$204,374.73	$228,321.22	11.7%
30%	15,000	3,285,000	$303,835.49	$339,115.77	11.6%
30%	20,000	4,380,000	$399,243.16	$445,857.23	11.7%
50%	4,000	1,460,000	$126,645.42	$140,275.24	10.8%
50%	7,500	2,737,500	$232,688.61	$257,125.52	10.5%
50%	10,000	3,650,000	$308,433.75	$344,442.90	11.7%
50%	15,000	5,475,000	$454,603.90	$502,198.77	10.5%
50%	20,000	7,300,000	$603,982.46	$667,015.99	10.4%
70%	4,000	2,044,000	$168,269.03	$185,182.74	10.1%
70%	7,500	3,832,500	$310,732.87	$341,327.07	9.8%
70%	10,000	5,110,000	$407,594.98	$447,960.92	9.9%
70%	15,000	7,665,000	$608,158.37	$668,067.83	9.9%
70%	20,000	10,220,000	$808,721.76	$888,174.75	9.8%
90%	4,000	2,628,000	$209,892.63	$230,090.24	9.6%
90%	7,500	4,927,500	$384,090.53	$420,842.02	9.6%
90%	10,000	6,570,000	$509,964.63	$558,540.30	9.5%
90%	15,000	9,855,000	$761,712.85	$833,936.90	9.5%
90%	20,000	13,140,000	$1,013,461.07	$1,109,333.50	9.5%

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

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$82,426.78	$90,291.93	9.5%
30%	5,000	1,095,000	$101,177.90	$110,791.12	9.5%
30%	10,000	2,190,000	$194,933.50	$213,287.04	9.4%
30%	20,000	4,380,000	$378,391.61	$414,225.77	9.5%
30%	40,000	8,760,000	$748,345.91	$819,141.35	9.5%
30%	50,000	10,950,000	$933,323.06	$1,021,599.14	9.5%
30%	70,000	15,330,000	$1,303,277.37	$1,426,514.71	9.5%
50%	4,000	1,460,000	$123,795.50	$134,725.22	8.8%
50%	5,000	1,825,000	$152,888.80	$166,332.73	8.8%
50%	10,000	3,650,000	$298,355.30	$324,370.26	8.7%
50%	20,000	7,300,000	$581,856.48	$633,013.49	8.8%
50%	40,000	14,600,000	$1,155,275.65	$1,256,716.78	8.8%
50%	50,000	18,250,000	$1,441,985.24	$1,568,568.43	8.8%
50%	70,000	25,550,000	$2,015,404.41	$2,192,271.72	8.8%
70%	4,000	2,044,000	$165,164.22	$179,158.51	8.5%
70%	5,000	2,555,000	$204,599.70	$221,874.34	8.4%
70%	10,000	5,110,000	$396,879.32	$430,555.70	8.5%
70%	20,000	10,220,000	$785,321.35	$851,801.21	8.5%
70%	40,000	20,440,000	$1,562,205.39	$1,694,292.21	8.5%
70%	50,000	25,550,000	$1,950,647.41	$2,115,537.72	8.5%
70%	70,000	35,770,000	$2,727,531.46	$2,958,028.72	8.5%
90%	4,000	2,628,000	$206,532.94	$223,591.80	8.3%
90%	5,000	3,285,000	$256,310.60	$277,415.95	8.2%
90%	10,000	6,570,000	$498,611.76	$539,949.56	8.3%
90%	20,000	13,140,000	$988,786.22	$1,070,588.92	8.3%
90%	40,000	26,280,000	$1,969,135.13	$2,131,867.64	8.3%
90%	50,000	32,850,000	$2,459,309.59	$2,662,507.01	8.3%
90%	70,000	45,990,000	$3,439,658.50	$3,723,785.73	8.3%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
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	$154,554.35	$169,572.03	9.7%
80%	13,000	7,592,000	$586,417.28	$653,862.23	11.5%
80%	23,000	13,432,000	$1,018,977.80	$1,138,850.02	11.8%
80%	33,000	19,272,000	$1,451,538.32	$1,623,837.80	11.9%
80%	43,000	25,112,000	$1,884,098.84	$2,108,825.59	11.9%
80%	53,000	30,952,000	$2,316,659.36	$2,593,813.38	12.0%
80%	63,000	36,792,000	$2,749,219.88	$3,078,801.17	12.0%
90%	3,000	1,971,000	$169,300.73	$185,957.10	9.8%
90%	13,000	8,541,000	$649,220.20	$723,766.11	11.5%
90%	23,000	15,111,000	$1,130,090.66	$1,262,526.12	11.7%
90%	33,000	21,681,000	$1,610,961.12	$1,801,286.13	11.8%
90%	43,000	28,251,000	$2,091,831.58	$2,340,046.14	11.9%
90%	53,000	34,821,000	$2,572,702.04	$2,878,806.15	11.9%
90%	63,000	41,391,000	$3,053,572.50	$3,417,566.16	11.9%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
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	$10,724,441.90	$11,878,070.60	10.8%
80%	260,000	151,840,000	$11,152,438.17	$12,352,258.30	10.8%
80%	270,000	157,680,000	$11,580,434.44	$12,826,446.00	10.8%
80%	280,000	163,520,000	$12,008,430.70	$13,300,633.70	10.8%
80%	290,000	169,360,000	$12,436,426.97	$13,774,821.40	10.8%
80%	300,000	175,200,000	$12,864,423.24	$14,249,009.10	10.8%
80%	310,000	181,040,000	$13,292,419.51	$14,723,196.80	10.8%
90%	250,000	164,250,000	$11,917,927.11	$13,188,625.91	10.7%
90%	260,000	170,820,000	$12,393,662.79	$13,715,235.83	10.7%
90%	270,000	177,390,000	$12,869,398.47	$14,241,845.74	10.7%
90%	280,000	183,960,000	$13,345,134.14	$14,768,455.65	10.7%
90%	290,000	190,530,000	$13,820,869.82	$15,295,065.56	10.7%
90%	300,000	197,100,000	$14,296,605.50	$15,821,675.48	10.7%
90%	310,000	203,670,000	$14,772,341.17	$16,348,285.39	10.7%

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2024 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	$644,683	$35,306	$833	($1,046)	$35,093	$58,364	$3,687	$62,051	$37,929	$3,239	$97,451	$203,156	$341,775	$1,083,601	$1,377,893
Schedule 15	$805	$100	$1	($2)	$99	$56	$5	$60	$63	$5	$174	$207	$449	$1,414	$3,906
Schedule 32	$114,216	$6,330	$148	($205)	$6,273	$9,195	$653	$9,848	$6,039	$516	$19,061	$34,127	$59,743	$190,081	$247,014
Schedule 38	$1,966	$115	$3	($4)	$114	$164	$11	$175	$151	$13	$495	$1,083	$1,741	$3,996	$4,491
Schedule 47	$1,694	$127	$2	($3)	$126	$131	$10	$141	$222	$19	$699	$1,164	$2,104	$4,065	$4,945
Schedule 49	$5,269	$313	$7	($8)	$312	$378	$30	$407	$714	$61	$2,342	$1,927	$5,043	$11,032	$12,234
Schedule 83															
Secondary	$209,402	$8,998	$176	($381)	$8,793	$16,522	$1,197	$17,719	$11,342	$969	$37,191	$32,407	$81,909	$317,822	$351,038
Schedule 85															
Secondary		$5,485	$147	($328)	$5,304									$5,304	$23,478
Primary		$1,931	$59	($134)	$1,856									$1,856	$4,264
Class Total	$193,105					$14,452	$1,101	$15,553	$11,642	$994	$30,923	$8,276	$51,835	$260,493	$260,493
Schedule 89															
Secondary		$0	$0	$0	$0						$0		$0	$0	$0
Primary		$2,834	$221	($340)	$2,715						$5,287		$5,287	$8,002	$10,529
Subtransmission		$168	$29	($44)	$152						$770		$770	$922	$1,463
Class Total	$86,547					$7,485	$593	$8,078	$7,494	$735			$8,228	$102,853	$102,853
Schedule 90-P	$202,162	$6,068	$261	($424)	$5,906	$13,890	$1,100	$14,989	$7,936	$662	$3,473		$12,070	$235,127	$236,586
Schedules 91 & 95	$2,412	$339	$3	($5)	$337	$167	$14	$181	$188	$16	$521	$651	$1,377	$4,306	$13,250
Schedules 92	$180	$6	$0	($0)	$6	$12	$1	$13	$6	$1	$16	$7	$30	$230	$244
Totals	$1,462,442	$68,119	$1,889	($2,922)	$67,086	$120,816	$8,400	$129,216	$83,726	$7,228	$198,402	$283,005	$572,361	$2,231,104	$2,654,682

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2024 COSTS TO RATE SCHEDULES ($000)

	Dist. Customer-Related TSM		Uncollectibles		Metering		Billing		Other Consumer		Subtotal				Total
	Single	Three	Single	Three	Single	Three	Single	Three	Single	Three	Single	Three	Fixed		Cost
Grouping	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Costs	Subtotal	Allocations
Schedule 7	$134,021	$0	$11,795	$0	$2,406	$0	$37,528	$0	$108,543	$0	$294,292	$0		$294,292	$1,377,893
Schedule 15	$114		$47		$0		$25		$0		$186	$0	$2,306	$2,492	$3,906
Schedule 32	$18,111	$18,415	$514	$382	$350	$260	$2,370	$1,762	$8,470	$6,298	$29,816	$27,117		$56,933	$247,014
Schedule 38	$17	$302	$0	$0	$2	$10	$17	$99	$7	$42	$42	$453		$495	$4,491
Schedule 47	$25	$366	$1	$8	$3	$35	$10	$104	$29	$300	$68	$813		$881	$4,945
Schedule 49	$6	$565	$0	$32	$0	$25	$5	$418	$2	$149	$13	$1,190		$1,202	$12,234
Schedule 83															
Secondary	$597	$17,741	$31	$382	$16	$197	$300	$3,638	$784	$9,529	$1,729	$31,487		$33,216	$351,038
Schedule 85															
Secondary		$5,164		$74		$49		$486		$12,403	$0	$18,175		$18,175	
Primary		$461		$11		$7		$73		$1,856	$0	$2,408		$2,408	$288,235
Schedule 89															
Secondary		$0		$0		$0		$0		$0	$0	$0		$0	
Primary		$96		$0		$0		$13		$2,417	$0	$2,527		$2,527	
Subtransmission		$145		$0		$0		$2		$394	$0	$541		$541	$114,845
Schedule 90-P		$13		$0		$0		$2		$1,444	$0	$1,459		$1,459	$236,586
Schedules 91 & 95	$809			$0		$0	$57		$0		$866	$0	$8,077	$8,944	$13,250
Schedule 92		$9		$0		$0		$4		$1	$0	$14		$14	$244
Totals	$153,699	$43,278	$12,389	$889	$2,777	$584	$40,310	$6,602	$117,836	$34,831	$327,011	$86,184	$10,383	$423,578	$2,654,682
													Reconcile to Ratespread		($0)

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2024

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
SCHEDULE 7							
Residential							
Allocations							
Functional Costs							
Basic Charge							
Single-Phase	$294,292	827,209	Customers	$29.65	per cust. per mo.		$294,321
Three-Phase	$0	0	Customers	$0.00	per cust. per mo.		$0
Trans. & Rel. Serv. Charge	$62,051	7,901,146	MWh	7.85	mills/kWh		$62,024
Distribution Charge	$341,775	7,901,146	MWh	43.26	mills/kWh		$341,804
Franchise Fees & Other	$35,093	7,901,146	MWh	4.44	mills/kWh		$35,081
Energy Charge	$644,683	7,901,146	MWh	81.59	mills/kWh		$644,654
Subtotal	$1,377,893						$1,377,884
Pricing							
Functional Costs							
Basic Charge							
Single-Phase-SFH		582,202		$13.00			$90,824
Single-Phase-MFH		245,007		$10.00			$29,401
Three-Phase		0	Customers	$13.00	per cust. per mo.		$0
Trans. & Rel. Serv. Charge		7,901,146	MWh	7.85	mills/kWh		$62,024
Distribution Charge		7,901,146	MWh	65.31	mills/kWh		$516,024
System Usage Charge Calculation							
Franchise Fees & Other		7,901,146	MWh	4.44	mills/kWh		$35,081
Cust Impact Offset		7,901,146	MWh	0.00	mills/kWh		$0
System Usage Charge		7,901,146	MWh	4.44	mills/kWh		$35,081
Energy Charge							
Block 1 (First 500 kWh)		4,319,462	MWh	81.59	mills/kWh		$352,425
Block 2 (501-1,000 kWh)		2,204,026	MWh	81.59	mills/kWh		$179,826
Block 3 (Over 1,000 kWh)		1,377,658	MWh	81.59	mills/kWh		$112,403
Subtotal							$1,378,008
					w/o CIO		$1,378,008
SCHEDULE 15							
Outdoor Area Lighting							
Allocations							
Functional Costs							
Basic Charge	$186	8,717	Customers	$1.78	per cust. per mo.		$186
Trans. & Rel. Serv. Charge	$60	13,335	MWh	4.53	mills/kWh		$60
Distribution Charge	$449	13,335	MWh	33.69	mills/kWh		$449
Franchise Fees & Other	$99	13,335	MWh	7.45	mills/kWh		$99
Energy Charge	$805	13,335	MWh	60.37	mills/kWh		$805
Fixed Charges	$2,306	13,335	MWh				$2,306
Subtotal	$3,906						$3,906
Pricing							
Functional Costs							
Trans. & Rel. Serv. Charge		13,335	MWh	4.53	mills/kWh		$60
Distribution Charge		13,335	MWh	47.64	mills/kWh		$635
System Usage Charge Calc							
Franchise Fees & Other		13,335	MWh	7.45	mills/kWh		$99
Cust Impact Offset		13,335	MWh	7.22	mills/kWh		$96
System Usage Charge		13,335	MWh	14.67	mills/kWh		$196
Energy Charge		13,335	MWh	60.47	mills/kWh		$806
Fixed Charges		13,335	MWh				$2,306
Subtotal							$4,004
					w/o CIO		$3,907

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
SCHEDULE 32							
General Service <30 kW							
Allocations							
Functional Costs							
Basic Charge							
Single-Phase	$29,816	55,566	Customers	$44.72	per cust. per mo.		$29,819
Three-Phase	$27,117	41,312	Customers	$54.70	per cust. per mo.		$27,117
Trans. & Rel. Serv. Charge	$9,848	1,545,473	MWh	6.37	mills/kWh		$9,845
Distribution Charge	$59,743	1,545,473	MWh	38.66	mills/kWh		$59,748
Franchise Fees & Other	$6,273	1,545,473	MWh	4.06	mills/kWh		$6,275
Energy Charge	$114,216	1,545,473	MWh	73.90	mills/kWh		$114,210
Subtotal	$247,014						$247,014
Pricing							
Functional Costs							
Basic Charge							
Single-Phase		55,566	Customers	$22.00	per cust. per mo.		$14,669
Three-Phase		41,312	Customers	$31.00	per cust. per mo.		$15,368
Trans. & Rel. Serv. Charge		1,545,473	MWh	6.37	mills/kWh		$9,845
Distribution Charge							
First 5 MWh		1,371,782	MWh	59.37	mills/kWh		$81,443
Over 5 MWh		173,690	MWh	30.00	mills/kWh		$5,211
System Usage Charge Calc							
Franchise Fees & Other		1,545,473	MWh	4.06	mills/kWh		$6,275
Cust Impact Offset		1,545,473	MWh	0.00	mills/kWh		$0
System Usage Charge		1,545,473	MWh	4.06	mills/kWh		$6,275
Energy Charge		1,545,473	MWh	73.90	mills/kWh		$114,210
Subtotal							$247,021
					w/o CIO		$247,021
SCHEDULE 38							
Time-of-Day G.S. >30 kW							
Allocations							
Functional Costs							
Basic							
Single-Phase	$42	51	Customers	$68.48	per cust. per mo.		$42
Three-Phase	$453	303	Customers	$124.56	per cust. per mo.		$453
Trans. & Rel. Serv. Charge	$175	27,293	MWh	6.42	per cust. per mo.		$175
Distribution Charges	$1,741	27,293	MWh	63.79	per cust. per mo.		$1,741
Franchise Fees & Other	$114	27,293	MWh	4.18	mills/kWh		$114
Energy Charge	$1,966	27,293	MWh	72.04	mills/kWh		$1,966
Subtotal	$4,491						$4,491
Pricing							
Functional Costs							
Basic							
Single-Phase		51	Customers	$35.00	per cust. per mo.		$21
Three-Phase		303	Customers	$35.00	per cust. per mo.		$127
Trans. & Rel. Serv. Charge		27,293	MWh	6.42	mills/kWh		$175
Distribution Charges		27,293	MWh	76.46	mills/kWh		$2,087
System Usage Charge							
Franchise Fees & Other		27,293	MWh	4.18	mills/kWh		$114
Cust Impact Offset		27,293	MWh	0.00	mills/kWh		$0
System Usage Charge		27,293	MWh	4.18	mills/kWh		$114
Energy Charge Calc							
On-Peak (special)		14,023	MWh	79.33	mills/kWh		$1,112
Off-Peak		13,270	MWh	64.33	mills/kWh		$854
Reactive Demand Charge		0	kVar	0.50	kVar		$0
Subtotal							$4,491
					w/o CIO		$4,491

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate Rate	Rate Unit	o	Annual Revenue ($000)
SCHEDULE 47							
Irrig. & Drain. Pump. - < 30 kW							
Allocations							
Functional Costs							
Basic Charge							
Single-Phase	$68	248	Customers	$45.60	per cust. per summ. mo.		$68
Three-Phase	$813	2,570	Customers	$52.70	per cust. per summ. mo.		$813
Trans. & Rel. Serv. Charge	$141	20,562	MWh	6.87	mills/kWh		$141
Distribution Charges	$2,104	20,562	MWh	102.30	mills/kWh		$2,104
Franchise Fees & Other	$126	20,562	MWh	6.14	mills/kWh		$126
Energy Charge	$1,694	20,562	MWh	82.38	mills/kWh		$1,694
Subtotal	$4,945						$4,945
Pricing							
Functional Costs							
Basic Charge							
Single-Phase		248	Customers	$39.00	per cust. per summ. mo.		$58
Three-Phase		2,570	Customers	$39.00	per cust. per summ. mo.		$601
Trans. & Rel. Serv. Charge		20,562	MWh	6.87	mills/kWh		$141
Distribution Charge Calc							
First 50 kWh per kW		12,661	MWh	120.74	mills/kWh		$1,529
Over 50 kWh per kW		7,901	MWh	100.74	mills/kWh		$796
System Usage Charge Calc							
Franchise Fees & Other		20,562	MWh	6.14	mills/kWh		$126
Cust Impact Offset		20,562	MWh	0.00	mills/kWh		$0
System Usage Charge		20,562	MWh	6.14	mills/kWh		$126
Energy Charge		20,562	MWh	82.38	mills/kWh		$1,694
Reactive Demand Charge		0	kVar	$0.50	kVar		$0
Subtotal with Consumer Impact Offset							$4,946
					w/o CIO		$4,946
SCHEDULE 49							
Irrig. & Drain. Pump. - > 30 kW							
Allocations							
Functional Costs							
Basic							
Single-Phase	$13	14	Customers	$150.16	per cust. per summ. mo.		$13
Three-Phase	$1,190	1,268	Customers	$156.36	per cust. per summ. mo.		$1,190
Trans. & Rel. Serv. Charge	$407	61,295	MWh	6.65	mills/kWh		$408
Distribution Charges	$5,043	61,295	MWh	82.28	mills/kWh		$5,043
Franchise Fees & Other	$312	61,295	MWh	5.09	mills/kWh		$312
Energy Charge	$5,269	61,295	MWh	85.97	mills/kWh		$5,270
Subtotal	$12,234						$12,235
Pricing							
Functional Costs							
Basic Charge							
Single-Phase		14	Customers	$50.00	per cust. per summ. mo.		$4
Three-Phase		1,268	Customers	$50.00	per cust. per summ. mo.		$380
Trans. & Rel. Serv. Charge		61,295	MWh	6.65	mills/kWh		$408
Distribution Charge Calc							
First 50 kWh per kW		37,480	MWh	103.38	mills/kWh		$3,875
Over 50 kWh per kW		23,816	MWh	83.38	mills/kWh		$1,986
System Usage Charge Calc							
Franchise Fees & Other		61,295	MWh	5.09	mills/kWh		$312
Cust Impact Offset		61,295	MWh	0.00	mills/kWh		$0
System Usage Charge		61,295	MWh	5.09	mills/kWh		$312
Energy Charge		61,295	MWh	85.97	mills/kWh		$5,270
Reactive Demand Charge		0	kVar	0.50	kVar		$0
Subtotal with Consumer Impact Offset							$12,234
					w/o CIO		$12,234

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
SCHEDULE 83							
General Service 31-200 kW							
Allocations							
Functional Costs							
Basic Charge							
Single-Phase Secondary	$1,729	893	Customers	$161.32	per cust, per mo.		$1,729
Three-Phase Secondary	$31,487	10,846	Customers	$241.93	per cust, per mo.		$31,487
Transmission & Related Service Charge	$17,719	8,818,293	kW demand	$2.01	per kW demand		$17,725
Distribution Charges							
Feeder Backbone	$37,191	12,345,611	kW faccap	$3.01	per kW faccap		$37,160
Feeder Local Facilities	$32,407	12,345,611	kW faccap	$2.63	per kW faccap		$32,469
Subtransmission Charge	$969	8,818,293	kW demand	$0.11	per kW demand		$970
Substation Charge	$11,342	8,818,293	kW demand	$1.29	per kW demand		$11,376
Secondary Franchise Fees & Other	$8,793	2,877,497	MWh	3.06	mills/kWh		$8,805
Secondary COS Energy Charge	$209,402	2,877,497	MWh	72.77	mills/kWh		$209,395
Subtotal	$351,038						$351,116
Pricing							
Functional Costs							
Basic Charge							
Secondary Single-Phase		893	Customers	$40.00	per cust, per mo.		$429
Secondary Three-Phase		10,846	Customers	$50.00	per cust, per mo.		$6,507
Trans. & Rel. Serv. Charge							
On-peak		8,640,964	kW demand	$2.45	per kW demand		$21,170
Off-peak		177,329	kW demand	$0.00	per kW demand		$0
Distribution Charges							
Secondary Facilities Charge							
First 30 kW		4,225,920	kW faccap	$5.70	<= 30 kW faccap		$24,088
Over 30 kW		8,119,691	kW faccap	$5.60	> 30 kW faccap		$45,470
Secondary Demand Charge							
On-peak		8,640,964	kW demand	$1.56	per kW demand		$13,480
Off-peak		177,329	kW demand	$0.00	per kW demand		$0
Secondary System Usage Charge Calc							
Franchise Fees & Other		2,877,497	MWh	3.06	mills/kWh		$8,805
Cust Impact Offset		2,877,497	MWh	0.00	mills/kWh		$0
Rate Design		2,877,497	MWh	7.45	mills/kWh		$21,437
System Usage Charge		2,877,497	MWh	10.51	mills/kWh		$30,242
COS Energy Charge							
On-peak		1,874,922	MWh	52.53	mills/kWh		$98,490
Off-peak		1,002,575	MWh	37.53	mills/kWh		$37,627
Generation Demand Charge		8,640,964	kW demand	8.48	per kW demand		$73,275
Reactive Demand Charge		533,365	kVar	$0.50	kVar		$267
Subtotal							$351,045
					w/o CIO		$351,045

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 85						
General Service 201-4,000 kW						
Allocations						
Functional Costs						
Basic Charge						
Secondary	$18,175	1,457	Customers	$1,039.51	per cust, per mo.	$18,175
Primary	$2,408	218	Customers	$920.52	per cust, per mo.	$2,408
Transmission & Related Service Charge	$15,553	7,084,544	kW on-peak	$2.20	per kW demand	$15,586
Distribution Charges						
Feeder Backbone	$30,923	11,435,611	kW faccap	$2.70	per kW faccap	$30,876
Feeder Local Facilities	$8,276	11,435,611	kW faccap	$0.72	per kW faccap	$8,234
Subtransmission Charge	$994	8,914,135	kW on-peak	$0.11	per kW on-peak demand	$981
Substation Charge	$11,642	8,914,135	kW on-peak	$1.31	per kW on-peak demand	$11,678
Secondary Franchise Fees & Other	$5,304	2,481,963	MWh	2.14	mills/kWh	$5,311
Primary Franchise Fees & Other	$1,856	1,008,774	MWh	1.84	mills/kWh	$1,856
COS Energy Charge	$193,105	2,748,849	MWh	70.25	mills/kWh	$193,107
Subtotal	$288,235					$288,211
Pricing						
Functional Costs						
Basic Charge						
Secondary		1,457	Customers	$1,040.00	per cust, per mo.	$18,183
Primary		218	Customers	$920.00	per cust, per mo.	$2,407
Secondary Trans. & Rel. Serv. Charge		5,489,078	kW on-peak	$2.45	per kW demand	$13,448
Primary Trans. & Rel. Serv. Charge		1,595,466	kW on-peak	$2.42	per kW demand	$3,861
Distribution Charges						
Secondary Facilities Charge						
First 200 kW		3,496,800	kW faccap	$3.18	per kW faccap	$11,120
Over 200 kW		5,158,046	kW faccap	$3.08	per kW faccap	$15,887
Primary Facilities Charge						
First 200 kW		523,200	kW faccap	$3.15	per kW faccap	$1,648
Over 200 kW		2,257,564	kW faccap	$3.05	per kW faccap	$6,886
Secondary Demand Charge		6,591,082	kW on-peak	$1.56	per kW demand	$10,282
Primary Demand Charge		2,323,052	kW on-peak	$1.54	per kW demand	$3,578
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		2,054,657	MWh	2.48	mills/kWh	$5,096
Cust Impact Offset		2,054,657	MWh	0.00	mills/kWh	$0
COS System Usage Charge		2,054,657	MWh	2.48	mills/kWh	$5,096
DA Franchise Fees & Other		427,305	MWh	0.51	mills/kWh	$218
Cust Impact Offset		427,305	MWh	0.00	mills/kWh	$0
DA System Usage Charge		427,305	MWh	0.51	mills/kWh	$218
Primary System Usage Charge Calc						
COS Franchise Fees & Other		694,191	MWh	2.45	mills/kWh	$1,701
Cust Impact Offset		694,191	MWh	0.00	mills/kWh	$0
COS System Usage Charge		694,191	MWh	2.45	mills/kWh	$1,701
DA Franchise Fees & Other		314,583	MWh	0.50	mills/kWh	$157
Cust Impact Offset		314,583	MWh	0.00	mills/kWh	$0
DA System Usage Charge		314,583	MWh	0.50	mills/kWh	$157
Secondary COS Energy Charge						
On-peak		1,330,566	MWh	51.18	mills/kWh	$68,098
Off-peak		724,092	MWh	36.18	mills/kWh	$26,198
Generation Demand Charge		5,489,078	kW on-peak	9.56	per kW demand	$52,476
Primary COS Energy Charge						
On-peak		430,163	MWh	50.68	mills/kWh	$21,801
Off-peak		264,028	MWh	35.68	mills/kWh	$9,421
Generation Demand Charge		1,595,466	kW on-peak	9.45	per kW demand	$15,077
Reactive Demand Charge		1,460,677	kVar	0.50	kVar	$730
Subtotal						$288,271
					w/o CIO	$288,271

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
SCHEDULE 89 GT 4,000 kW							
General Service							
Allocations							
Functional Costs							
Secondary Basic Charge	$0	0	Customers	$4,950.96	per cust, per mo.		$0
Primary Basic Charge	$2,527	43	Customers	$4,897.09	per cust, per mo.		$2,527
Subtransmission Basic Charge	$541	7	Customers	$6,441.54	per cust, per mo.		$541
Transmission & Related Service Charge	$8,078	2,597,536	kW on-peak	$3.11	per kW on-peak demand		$8,078
Distribution Charges							
Feeder Backbone	$6,057	5,706,880	kW faccap	$1.06	per kW faccap		$6,049
Feeder Local Facilities							$0
Subtransmission Demand Charge	$735	5,349,986	kW on-peak	$0.14	per kW on-peak demand		$749
Substation Demand Charge	$7,494	4,551,657	kW on-peak	$1.65	per kW on-peak demand		$7,510
Secondary Franchise Fees & Other	$0	0	MWh	1.07	mills/kWh		$0
Primary Franchise Fees & Other	$2,715	2,568,821	MWh	1.06	mills/kWh		$2,723
Subtransmission Franchise Fees & Other	$152	333,764	MWh	0.46	mills/kWh		$154
Energy Charge	$86,547	1,296,518	MWh	66.75	mills/kWh		$86,543
Subtotal	$114,845						$114,874
Pricing							
Functional Costs							
Secondary Basic Charge		0	Customers	$4,950.00	per cust, per mo.		$0
Primary Basic Charge		43	Customers	$4,900.00	per cust, per mo.		$2,528
Subtransmission Basic Charge		7	Customers	$6,440.00	per cust, per mo.		$541
Secondary Trans. & Rel. Serv. Charge		0	kW on-peak	$2.45	per kW on-peak demand		$0
Primary Trans. & Rel. Serv. Charge		2,328,939	kW on-peak	$2.42	per kW on-peak demand		$5,636
Subtransmission Trans. & Rel. Serv. Charge		268,597	kW on-peak	$2.38	per kW on-peak demand		$639
Distribution Charges							
Secondary Facilities Charge							
First 1,000 kW		0	kW faccap	$1.61	per kW faccap		$0
1,001-4,000 kW		0	kW faccap	$1.61	per kW faccap		$0
Greater than 4,000 kW		0	kW faccap	$1.30	per kW faccap		$0
Primary Facilities Charge							
First 1,000 kW		516,000	kW faccap	$1.59	per kW faccap		$820
1,001-4,000 kW		1,548,000	kW faccap	$1.59	per kW faccap		$2,461
Greater than 4,000 kW		2,790,522	kW faccap	$1.28	per kW faccap		$3,572
Subtransmission Facilities Charge							
First 1,000 kW		84,000	kW faccap	$1.59	per kW faccap		$134
1,001-4,000 kW		252,000	kW faccap	$1.59	per kW faccap		$401
Greater than 4,000 kW		516,358	kW faccap	$1.28	per kW faccap		$661
Secondary Demand Charge		0	kW on-peak	$1.56	per kW on-peak demand		$0
Primary Demand Charge		4,551,657	kW on-peak	$1.54	per kW on-peak demand		$7,010
Subtransmission Demand Charge		798,329	kW on-peak	$0.12	per kW on-peak demand		$96
Secondary System Usage Charge Calc							
COS Franchise Fees & Other		0	MWh	2.05	mills/kWh		$0
Cust Impact Offset		0	MWh	0.00	mills/kWh		$0
COS System Usage Charge		0	MWh	2.05	mills/kWh		$0
DA Franchise Fees & Other		0	MWh	0.14	mills/kWh		$0
Cust Impact Offset		0	MWh	0.00	mills/kWh		$0
DA System Usage Charge		0	MWh	0.14	mills/kWh		$0
Primary System Usage Charge Calc							
COS Franchise Fees & Other		1,240,557	MWh	2.03	mills/kWh		$2,518
Cust Impact Offset		1,240,557	MWh	0.00	mills/kWh		$0
COS System Usage Charge		1,240,557	MWh	2.03	mills/kWh		$2,518
DA Franchise Fees & Other		1,328,264	MWh	0.14	mills/kWh		$186
Cust Impact Offset		1,328,264	MWh	0.00	mills/kWh		$0
DA System Usage Charge		1,328,264	MWh	0.14	mills/kWh		$186
Subtransmission System Usage Charge Calc							
COS Franchise Fees & Other		55,961	MWh	2.01	mills/kWh		$112
Cust Impact Offset		55,961	MWh	0.00	mills/kWh		$0
COS System Usage Charge		55,961	MWh	2.01	mills/kWh		$112
DA Franchise Fees & Other		277,803	MWh	0.15	mills/kWh		$42
Cust Impact Offset		277,803	MWh	0.00	mills/kWh		$0
DA System Usage Charge		277,803	MWh	0.15	mills/kWh		$42
Secondary Energy Charge							
On-peak		0	MWh	73.58	mills/kWh		$0
Off-peak		0	MWh	58.58	mills/kWh		$0
Primary Energy Charge							
On-peak		733,801	MWh	72.85	mills/kWh		$53,457
Off-peak		506,756	MWh	57.85	mills/kWh		$29,316
Subtransmission Energy Charge							
On-peak		38,823	MWh	72.10	mills/kWh		$2,799
Off-peak		17,138	MWh	57.10	mills/kWh		$979
Reactive Demand Charge		1,802,005	kVar	0.50	kVar		$901
Subtotal							$114,809
					w/o CIO		$114,809

Secondary Losses	1.0640
Primary Losses	1.0530
Delta Losses	0.01100

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	o	Annual Revenue ($000)
SCHEDULE 90							
Primary Voltage Service							
Allocations							
Functional Costs							
Primary Basic Charge	$1,459	6	Customers	$20,263.80	per cust, per mo.		$1,459
Subtransmission Basic Charge		0	Customers	$20,263.80	per cust, per mo.		$0
Transmission & Related Service Charge	$14,989	4,820,175	kW on-peak	$3.11	per kW on-peak demand		$14,991
Distribution Charges							
Feeder Backbone	$3,473	5,015,686	kW faccap	$0.69	per kW faccap		$3,461
Subtransmission Demand Charge	$662	4,820,175	kW on-peak	$0.14	per kW on-peak demand		$675
Substation Demand Charge	$7,936	4,820,175	kW on-peak	$1.65	per kW on-peak demand		$7,953
Primary Franchise Fees & Other	$5,906	3,200,967	MWh	1.85	mills/kWh		$5,922
Subtransmission Franchise Fees & Other		0	MWh	1.87	mills/kWh		$0
Energy Charge	$202,162	3,200,967	MWh	63.16	mills/kWh		$202,173
Subtotal	$236,586						$236,634
Pricing							
Functional Costs							
Primary Basic Charge		6	Customers	$20,300.00	per cust, per mo.		$1,462
Subtransmission Basic Charge		0	Customers	$20,300.00	per cust, per mo.		$0
Primary Trans. & Rel. Serv. Charge		4,820,175	kW on-peak	$2.42	per kW on-peak demand		$11,665
Subtransmission Trans & Rel Serv. Charge		0	kW on-peak	$2.38	per kW on-peak demand		$0
Distribution Charges							
Primary Facilities Charge							
First 4,000 kW		288,000	kW faccap	$1.75	per kW faccap		$504
Over 4,000 kW		4,727,686	kW faccap	$1.44	per kW faccap		$6,808
Subtransmission Facilities Charge							
First 4,000 kW		0	kW faccap	$1.75	per kW faccap		$0
Over 4,000 kW		0	kW faccap	$1.44	per kW faccap		$0
Primary Demand Charge		4,820,175	kW on-peak	$1.54	per kW on-peak demand		$7,423
Subtransmission Demand Charge		0	kW on-peak	$0.12	per kW on-peak demand		$0
Primary System Usage Charge Calc >250MWa							
COS Franchise Fees & Other		3,200,967	MWh	1.85	mills/kWh		$5,922
Cust Impact Offset		3,200,967	MWh	0.00	mills/kWh		$0
COS System Usage Charge		3,200,967	MWh	1.85	mills/kWh		$5,922
Primary System Usage Charge Calc 30-250 Mwa							
COS Franchise Fees & Other		0	MWh	1.90	mills/kWh		$0
Cust Impact Offset		0	MWh	0.00	mills/kWh		$0
COS System Usage Charge		0	MWh	1.90	mills/kWh		$0
Subtransmission System Usage Charge Calc >250MWa							
COS Franchise Fees & Other		0	MWh	1.83			$0
Cust Impact Offset		0	MWh	0.00			$0
COS System Usage Charge		0	MWh	1.83	mills/kWh		$0
Subtransmission System Usage Charge Calc 30-250MWa							
COS Franchise Fees & Other		0	MWh	1.88			$0
Cust Impact Offset		0	MWh	0.00			$0
COS System Usage Charge		0	MWh	1.88	mills/kWh		$0
Primary Energy Charge >250Mwa							
On-peak		1,837,906	MWh	69.54	mills/kWh		$127,808
Off-peak		1,363,061	MWh	54.54	mills/kWh		$74,341
Primary Energy Charge 30-250MWa							
On-peak		0	MWh	71.48	mills/kWh		$0
Off-peak		0	MWh	56.06	mills/kWh		$0
Subtransmission Energy Charge >250MWa							
On-peak		0	MWh	68.76	mills/kWh		$0
Off-peak		0	MWh	53.76	mills/kWh		$0
Subtransmission Energy Charge 30-250MWa							
On-peak		0	MWh	70.68	mills/kWh		$0
Off-peak		0	MWh	55.26	mills/kWh		$0
Reactive Demand Charge		1,279,438	kVar	$0.50	kVar		$640
							$236,572
					w/o CIO		$236,572

Primary Losses	1.0530
Sub Trans Losses	1.04
Delta Losses	0.01140

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2024

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULES 91 & 95						
Street & Highway Lighting						
Allocations						
Functional Costs						
Basic Charge	$866	186	Customers	$388.10	per cust, per mo.	$866
Trans. & Rel. Serv. Charge	$181	39,857	MWh	4.53	mills/kWh	$181
Distribution Charge	$1,377	39,857	MWh	34.54	mills/kWh	$1,377
Franchise Fees & Other	$337	39,857	MWh	8.46	mills/kWh	$337
COS Energy Charge	$2,412	39,857	MWh	60.51	mills/kWh	$2,412
Pricing Fixed Charges	$8,077					$8,077
Fur Subtotal	$13,250					$13,250
Trans. & Rel. Serv. Charge		39,857	MWh	4.53	mills/kWh	$181
Distribution Charge		39,857	MWh	56.27	mills/kWh	$2,243
System Usage Charge Calc						
Franchise Fees & Other		39,857	MWh	8.46	mills/kWh	$337
Cust Impact Offset		39,857	MWh	(2.42)	mills/kWh	($96)
System Usage Charge		39,857	MWh	6.04	mills/kWh	$241
COS Energy Charge		39,857	MWh	60.47	mills/kWh	$2,410
SCHEDUL Fixed Charges		39,857	MWh			$8,077
Traffic Sig Subtotal						$13,151
Allocations						
Functional Costs					w/o CIO	$13,248
Basic Charge	$14	16	Customers	$75.09	per cust, per mo.	$14
Trans. & Rel. Serv. Charge	$13	2,723	MWh	4.89	mills/kWh	$13
Distribution Charge	$30	2,723	MWh	11.06	mills/kWh	$30
Franchise Fees & Other	$6	2,723	MWh	2.25	mills/kWh	$6
Pricing COS Energy Charge	$180	2,723	MWh	66.17	mills/kWh	$180
Fur Subtotal	$244					$244
Trans. & Rel. Serv. Charge		2,723	MWh	4.89	mills/kWh	$13
Distribution Charge		2,723	MWh	16.36	mills/kWh	$45
System Usage Charge Calc						
Franchise Fees & Other		2,723	MWh	2.25	mills/kWh	$6
Cust Impact Offset		2,723	MWh	0.00	mills/kWh	$0
System Usage Charge		2,723	MWh	2.25	mills/kWh	$6
COS Energy Charge		2,723	MWh	66.17	mills/kWh	$180
Subtotal						$244
Summary of Inputs						
Functional Costs					w/o CIO	$244

	Allocated Inputs	DesSumm	Deltas			
Basic Charge	$413,195	$413,195	($0)			
Trans. & Rel. Serv. Charge	$129,216	$129,216	$0			
Distribution Charge	$572,361	$572,361	$0			
Fixed Charges	$10,383	$10,383	$0			
Franchise Fees & Other	$67,086	$67,086	$0			
Functiona Energy Charge	$1,462,442	$1,462,442	$0			
Basic Char Subtotal	$2,654,682	$2,654,682				
Trans. & Rel. Serv. Charge						
Distribution Charges	Annual					
Fixed Charges	Revenue	Revenue	Deltas			
System Usage Charge	$183,512	$183,512	$0			
Energy Charge	$129,267	$129,240	($27)	($27)	(Voluntary TOU)	
Reactive	$778,199	$778,199	$0	$0	(Voluntary TOU)	
Subtotal	$10,383	$10,383	$0			
Note: figures are before employee discount and Schedule 12	$88,545	$88,545	$0			
	$1,462,353	$1,462,387	$34	$34	(Voluntary TOU)	
On-peak demand	$2,538	$2,538	$0			
Facility Capacity	$2,654,796	$2,654,804	$8	$8		$2,654,796
kVar						
	27,725,259	27,725,259	0			
	34,503,788	34,503,788	0			
	5,075,485	5,075,485	0			

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at Current Prices ($000)	2024 Allocated Costs ($000)	Percent Change	Impact Offset Amount	Impact Offset MWH	CIO mills/kWh	CIO Revenues
Schedule 7	7,901,146	$1,219,155	$1,410,762	15.7%		7,901,146	0.00	$0
Schedule 15	13,335	$3,704	$3,946	6.5%			7.22	$96
Schedule 32	1,545,473	$217,941	$252,516	15.9%		1,545,473	0.00	$0
Schedule 38	27,293	$4,118	$4,580	11.2%		27,293	0.00	$0
Schedule 47	20,562	$4,803	$5,027	4.7%				$0
Schedule 49	61,295	$11,164	$12,484	11.8%		61,295	0.00	$0
Schedule 83	2,877,497	$320,935	$361,167	12.5%		2,877,497	0.00	$0
Schedule 85	2,748,849	$262,138.38	$297,532.63	13.5%		2,748,849	0.00	$0
Schedule 89/75	1,296,518	$108,887.14	$119,075	9.4%		1,296,518	0.00	$0
Schedule 90	3,200,967	$222,405	$246,317	10.8%		3,200,967	0.00	$0
Schedules 91 & 95	39,857	$13,009	$13,369	2.8%			(2.42)	($96)
Schedule 92	2,723	$223	$253	13.4%			0.00	$0
COS TOTALS	19,735,515							
Sch 485 Energy	741,889					741,889	0.00	$0
Sch 489 Energy	1,427,748						0.00	$0
Sch 689 Energy	178,318						0.00	$0
Totals	22,083,470	$2,388,482	$2,727,028	14.2%	$0	20,400,927		($0)

Note: does not include Sch 76R	$0	$0
Note: does not include employee discount	($1,310)	($1,512)
Reconcile CIO worksheet to revenues	$2,387,172	$2,725,516
	$2,392,594	$2,728,438
	(5,422)	(2,922)

Schedules	CIO Allocation	MWh	CIO (mills/kWh)
38		27,293	0
49		61,295	0
83	$0	2,877,497	0
85/485/585	$0	3,490,737	0
89/489/589/689	$0	2,902,584	0
90/490/590	$0	3,200,967	0
Totals	$0	9,594,289	

PORTLAND GENERAL ELECTRIC
2024 Test Period Functionalized Revenue Requirement

Function	Amount	Spread
PRODUCTION	$1,470,725	$1,470,725
TRANSMISSION	$121,526	$121,526
ANCILLARY	$8,450	$8,450
DISTRIBUTION	$866,686	$866,686
METERING	$3,381	$3,381
BILLING	$47,194	$47,194
CONSUMER	$153,583	$153,583
TOTALS	$2,671,545	$2,671,545
Schedule 129		($2,363)
Scheduel 139		($559)
Employee Discount		$1,502
Partial Requirements Transmission		$0
Partial Requirements Distribution		$0
Spread Total		$2,670,125

Note: Employee discount is allocated to distribution

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2024 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$610,668	$607,229
Net Variable Power Costs	860,056	$855,212
Production Costs	$1,470,725	$1,462,442
Ancillary Services	$8,450	$8,400
Transmission		
Transmission	$121,526	
Partial Requirements Daily Demand	$0	
Transmission Costs	$121,526	$120,816
Distribution Services	$866,686	
Franchise	($68,528)	
Uncollectibles	($13,358)	
Trojan Decommissioning	($1,900)	
Partial Requirements Daily Demand	$0	
Employee Discount	$1,502	$1,502
Distribution Costs	$784,403	$779,721
Consumer Services		
Metering Services	$3,381	$3,361
Billing Services	$47,194	$46,912
Other Consumer Services	$153,583	$152,667
Franchise Fees	$68,528	$68,119
Uncollectibles	$13,358	$13,278
Trojan Decommissioning	$1,900	$1,889
Schedule 129	($2,363)	($2,363)
Schedule 139	($559)	($559)
Totals	$2,670,125	$2,654,682
Net of employee discount	$2,668,623	$2,653,180
Net of Sch 129 and Sch 139	$2,671,545	$2,656,102
Calendar MWH (COS & ESS)	22,216,066	
Cycle MWH (COS & ESS)	22,083,470	
Cycle/Cal Ratio	99.40%	
COS Calendar Energy MWH	19,851,537	
COS Cycle MWH	19,735,515	
Cycle/Cal Ratio	99.42%	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF GENERATION REVENUE REQUIREMENT TO COS CUSTOMERS
2024

Schedules	COS Calendar Energy	Marginal Energy Costs ($000)	Generation Capacity Allocation	Marginal Capacity Costs ($000)	Marginal Capacity & Energy Costs ($000)	Capacity & Energy Allocation Percent	Allocation of Load Following ($000)	Allocated Capacity & Energy Costs ($000)	Cycle Basis Costs ($000)	Cycle Basis Pct.	Capacity Marginal Costs	Energy Marginal Costs	Capacity Percent	Energy Percent
Schedule 7	7,932,801	$495,516	51.59%	$272,388	$767,904	43.89%	$1,824	$647,266	$644,683	44.1%	$272,388	$495,516	35.5%	64.5%
Schedule 15	13,379	$706	0.05%	$252	$958	0.05%	$2	$808	$805	0.1%	$252	$706	26.3%	73.7%
Schedule 32	1,551,487	$96,124	7.56%	$39,907	$136,031	7.77%	$323	$114,661	$114,216	7.8%	$39,907	$96,124	29.3%	70.7%
Schedule 38	27,385	$1,728	0.12%	$613	$2,341	0.13%	$6	$1,973	$1,966	0.1%	$613	$1,728	26.2%	73.8%
Schedule 47	21,203	$1,412	0.12%	$660	$2,072	0.12%	$5	$1,747	$1,694	0.1%	$660	$1,412	31.8%	68.2%
Schedule 49	61,012	$4,108	0.40%	$2,114	$6,223	0.36%	$15	$5,245	$5,269	0.4%	$2,114	$4,108	34.0%	66.0%
Schedule 83	2,888,377	$179,585	13.22%	$69,784	$249,370	14.25%	$592	$210,194	$209,402	14.3%	$69,784	$179,585	28.0%	72.0%
Schedule 85	2,764,385	$170,743	11.10%	$58,588	$229,330	13.11%	$1,439	$194,197	$193,105	13.2%	$58,588	$170,743	25.5%	74.5%
Schedule 89/75	1,320,397	$78,885	4.59%	$24,235	$103,120	5.89%	$1,466	$88,141	$86,547	5.9%	$24,235	$78,885	23.5%	76.5%
Schedule 90	3,228,485	$190,662	11.11%	$58,681	$249,343	14.25%	($5,680)	$203,900	$202,162	13.8%	$58,681	$190,662	23.5%	76.5%
Schedule 91/95	39,893	$2,111	0.14%	$753	$2,864	0.16%	$7	$2,414	$2,412	0.2%	$753	$2,111	26.3%	73.7%
Schedule 92	2,732	$166	0.01%	$48	$214	0.01%	$1	$181	$180	0.0%	$48	$166	22.6%	77.4%
TOTAL	19,851,537	$1,221,746	100.0%	$528,024	$1,749,771	100.00%	($0)	$1,470,725	$1,462,442		$528,024	$1,221,746	30.2%	69.8%
4 hour Battery				$138.52		**TARGET**		**$1,470,725**						
Projected Peak Load				3,812										
Marginal Capacity Costs ($000)				$528,024										

102.79% Sch 90 30-250 Mwa differential

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	1,572.6	$87.34	$137,355	48.31%	$58,364
Schedule 15	1.5	$87.34	$131	0.05%	$56
Schedule 32	247.8	$87.34	$21,641	7.61%	$9,195
Schedule 38	4.4	$87.34	$386	0.14%	$164
Schedule 47	3.5	$87.34	$309	0.11%	$131
Schedule 49	10.2	$87.34	$888	0.31%	$378
Schedule 83	445.2	$87.34	$38,883	13.68%	$16,522
Schedule 85	389.4	$87.34	$34,011	11.96%	$14,452
Schedule 89	173.1	$87.34	$15,121	5.32%	$6,425
Schedule 90-P	402.8	$87.34	$35,183	12.37%	$14,950
Schedules 91/95	4.5	$87.34	$393	0.14%	$167
Schedule 92	0.3	$87.34	$29	0.01%	$12
Totals	3,255.4		$284,330		
Target				100.00%	$120,816
Unit Marginal Cost $/kW		**$87.34**			

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE REVENUE REQUIREMENT
2024

Schedules	Production Allocation Percent	Class Revenue Requirement
Schedule 7	43.89%	$3,687
Schedule 15	0.05%	$5
Schedule 32	7.77%	$653
Schedule 38	0.13%	$11
Schedule 47	0.12%	$10
Schedule 49	0.36%	$30
Schedule 83	14.25%	$1,197
Schedule 85	13.11%	$1,101
Schedule 89	5.89%	$495
Schedule 90-P	14.25%	$1,197
Schedules 91/95	0.16%	$14
Schedule 92	0.01%	$1
TOTAL	100.00%	$8,400
	TARGET	$8,400

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2024

Schedules	Cycle Generation Revenues	Allocation Percent	Class Revenue Requirement	MWh	mills/kWh
Schedule 7	$644,812,518	44.11%	$833	7,901,146	0.11
Schedule 15	$806,367	0.06%	$1	13,335	0.08
Schedule 32	$114,241,336	7.81%	$148	1,545,473	0.10
Schedule 38	$1,966,092	0.13%	$3	27,293	0.09
Schedule 47	$1,693,927	0.12%	$2	20,562	0.11
Schedule 49	$5,269,567	0.36%	$7	61,295	0.11
Schedule 83	$136,116,305	9.31%	$176	2,877,497	0.06
Schedule 85-S	$113,712,182	7.78%	$147	2,481,963	0.06
Schedule 89-S	$0	0.00%	$0	0	0.00
Schedule 85-P	$45,308,743	3.10%	$59	1,008,774	0.06
Schedule 89-P	$171,227,800	11.71%	$221	2,568,821	0.09
Schedule 89-T	$22,064,020	1.51%	$29	333,764	0.09
Schedule 90-P	$202,149,350	13.83%	$261	3,200,967	0.08
Schedule 91/95	$2,410,153	0.16%	$3	39,857	0.08
Schedule 92	$180,181	0.01%	$0	2,723	0.09
TOTAL	$1,461,958,540		$1,889	22,083,470	
		TARGET	$1,889		

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2024

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	$636,900	$62,051	$644,683		$1,343,633	$16,735	$1,630	$16,940		$35,306
Schedule 15	$2,942	$60	$805		$3,808	$77	$2	$21		$100
Schedule 32	$116,824	$9,848	$114,216		$240,889	$3,070	$259	$3,001		$6,330
Schedule 38	$2,238	$175	$1,966		$4,380	$59	$5	$52		$115
Schedule 47	$2,986	$141	$1,694		$4,821	$78	$4	$45		$127
Schedule 49	$6,252	$407	$5,269		$11,929	$164	$11	$138		$313
Schedule 83	$115,300	$17,719	$209,402		$342,421	$3,030	$466	$5,502		$8,998
Schedule 85	$72,623	$15,553	$193,105	$1,025	$282,306	$1,908	$409	$5,074	$24	$7,415
Schedule 89	$17,602	$8,078	$86,547	$1,897	$114,125	$463	$212	$2,274	$53	$3,001
Schedule 90	$13,791	$14,989	$202,162		$230,942	$362	$394	$5,312		$6,068
Schedules 91/95	$10,323	$181	$2,412		$12,916	$271	$5	$63		$339
Schedule 92	$45	$13	$180		$238	$1	$0	$5		$6
TOTALS	$997,827	$129,216	$1,462,442	$2,922	$2,592,407	$26,219	$3,395	$38,428	$77	$68,119

Franchise Fee Revenue Requirement **$68,119**

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	7,901,146	2.12	7,901,146	0.21	7,901,146	2.14	0		4.47			
Schedule 15	13,335	5.80	13,335	0.12	13,335	1.59	0		7.50	5.80	1.71	1.71 (melded lighting)
Schedule 32	1,545,473	1.99	1,545,473	0.17	1,545,473	1.94	0		4.10	1.99	2.11	
Schedule 38	27,293	2.15	27,293	0.17	27,293	1.89	0		4.22	2.15	2.06	
Schedule 47	20,562	3.82	20,562	0.18	20,562	2.16	0		6.16			
Schedule 49	61,295	2.68	61,295	0.17	61,295	2.26	0		5.11	2.68	2.43	
Schedule 83	2,877,497	1.05	2,877,497	0.16	2,877,497	1.91	0		3.13	1.05	2.07	
Schedule 85-S	2,481,963	0.55	2,054,657	0.15	2,054,657	1.85	427,305	0.03	2.55	0.58	1.97	
Schedule 89-S	0	0.16	0	0.17	0	1.77	0	0.03	2.10	0.19	1.91	
Schedule 85-P	1,008,774	0.54	694,191	0.15	694,191	1.83	314,583	0.03	2.52	0.58	1.95	
Schedule 89-P	2,568,821	0.16	1,240,557	0.16	1,240,557	1.75	1,328,264	0.03	2.08	0.19	1.89	
Schedule 89-T/75-T	333,764	0.16	55,961	0.16	55,961	1.74	277,803	0.03	2.05	0.19	1.86	
Schedule 90-P	3,200,967	0.11	3,200,967	0.12	3,200,967	1.66			1.90	0.11	1.78	
Schedule 90-T	0	0.11	0	0.12	0	1.66			1.90	0.11	1.78	
Schedule 91/95	39,857	6.81	39,857	0.12	39,857	1.59	0		8.51	6.81	1.71	
Schedule 92	2,723	0.43	2,723	0.13	2,723	1.74	0		2.30	0.43	1.87	
TOTALS	22,083,470		19,735,515		19,735,515		2,347,955					

Voltage Differentials

Sch 85 Secondary/PrimaryDelta	1.110%	0.01		0.00	0.02
Secondary/PrimaryDelta	1.110%	0.00		0.00	0.02
Secondary/Subtransmission Delta	2.240%	0.00		0.00	0.04
Prim/Subtransmission Delta	1.130%	0.00			

Revenues

Schedules	MWh	Fran. Fee mills/kWh	Fran. Fee Revenues
Schedule 7	7,901,146	4.47	$35,306
Schedule 15	13,335	7.50	$100
Schedule 32	1,545,473	4.10	$6,330
Schedule 38	27,293	4.22	$115
Schedule 47	20,562	6.16	$127
Schedule 49	61,295	5.11	$313
Schedule 83	2,877,497	3.13	$8,998
Schedule 85-S	2,054,657	2.55	$5,236
Schedule 485-S	427,305	0.58	$248
Schedule 89-S	0	2.10	$0
Schedule 489-S	0	0.19	$0
Schedule 85-P	694,191	2.52	$1,750
Schedule 485-P	314,583	0.58	$181
Schedule 89-P	1,240,557	2.08	$2,578
Schedule 489-P	1,328,264	0.19	$255
Schedule 89-T/75-T	55,961	2.05	$115
Schedule 489-T	277,803	0.19	$53
Schedule 90-P	3,200,967	1.90	$6,068
Schedule 90-T	0	1.90	$0
Schedule 91/95	39,857	8.51	$339
Schedule 92	2,723	2.30	$6
TOTALS	22,083,470		$68,119

ALLOCATION OF TRANSITION ADJUSTMENT

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 7	7,901,146	35.8%	($1,046)	(0.13)
Schedule 15	13,335	0.1%	($2)	(0.13)
Schedule 32	1,545,473	7.0%	($205)	(0.13)
Schedule 38	27,293	0.1%	($4)	(0.13)
Schedule 47	20,562	0.1%	($3)	(0.13)
Schedule 49	61,295	0.3%	($8)	(0.13)
Schedule 83	2,877,497	13.0%	($381)	(0.13)
Schedule 85-S	2,478,555	11.2%	($328)	(0.13)
Schedule 89-S	0	0.0%	$0	(0.13)
Schedule 85-P	1,008,774	4.6%	($134)	(0.13)
Schedule 89	2,568,821	11.6%	($340)	(0.13)
Schedule 89-T/75-T	333,764	1.5%	($44)	(0.13)
Schedule 90-P	3,200,967	14.5%	($424)	(0.13)
Schedules 91/95	39,857	0.2%	($5)	(0.13)
Schedule 92	2,723	0.0%	($0)	(0.13)
TOTAL	22,080,062	100.00%	($2,922)	(0.13)
		TARGET	($2,922)	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2024

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	88.83%	$11,795
Three Phase	0.00%	$0
Schedule 15		
Residential	0.16%	$21
Commercial	0.20%	$27
Schedule 32		
Single Phase	3.87%	$514
Three Phase	2.88%	$382
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.00%	$0
Schedule 47		
Single Phase	0.01%	$1
Three Phase	0.06%	$8
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.24%	$32
Schedule 83		
Single Phase	0.24%	$31
Three Phase	2.88%	$382
Schedule 85		
Secondary	0.56%	$74
Primary	0.08%	$11
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%	$13,278
TARGET		$13,278

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2024

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	827,209	Customers	$21.08	$17,438	$20,550
		Three-Phase Customers	0	Customers	$47.38	$0	$0
	Transformer & Service						
		Single-Phase Customers	827,209	Customers	$116.40	$96,287	$113,471
		Three-Phase Customers	0	Customers	$154.70	$0	$0
FACILITIES	Feeder Backbone						
		Single-Phase Customers	2,026,783	kW, rateclass peak	$40.80	$82,693	$97,451
		Three-Phase Customers	0	kW, rateclass peak	$40.80	$0	$0
	Feeder Local Facilities						
		Single-Phase Customers	3,308,837	Design Demand	$52.10	$172,390	$203,156
		Three-Phase Customers	0	Design Demand	$52.10	$0	$0
DEMAND	Subtransmission		2,066,508	kW, rateclass peak	$1.33	$2,748	$3,239
	Substation		2,026,783	kW, rateclass peak	$15.88	$32,185	$37,929
SUBTOTAL						$403,742	$475,795
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		6,663	Lights	$1.32	$9	$10
	Transformer & Service		6,663	Lights	$3.28	$22	$26
FACILITIES	Feeder Backbone		413	kW, rateclass peak	$43.89	$18	$21
	Feeder Local Facilities		413	Design Demand	$52.03	$21	$25
DEMAND	Subtransmission		421	kW, rateclass peak	$1.33	$1	$1
	Substation		413	kW, rateclass peak	$15.88	$7	$8
FIXED	Luminaires & Poles						$283
SUBTOTAL						$77	$374
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		14,368	Lights	$1.32	$19	$22
	Transformer & Service		14,368	Lights	$3.28	$47	$56
FACILITIES	Feeeder Backbone		2,956	kW, rateclass peak	$43.89	$130	$153
	Feeder Local Facilities		2,956	Design Demand	$52.03	$154	$181
DEMAND	Subtransmission		3,014	kW, rateclass peak	$1.33	$4	$5
	Substation		2,956	kW, rateclass peak	$15.88	$47	$55
FIXED	Luminaires & Poles						$2,023
SUBTOTAL						$401	$2,495
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$33
	Transformer & Service						$81
FACILITIES	Feeeder Backbone						$174
	Feeder Local Facilities						$207
DEMAND	Subtransmission						$5
	Substation						$63
FIXED	Luminaires & Poles						**$2,306**
SUBTOTAL							$2,869

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2024

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 32 Small Non-residential General Service							
CUSTOMER	Meters						
		Single-Phase Customers	55,566	Customers	$43.59	$2,422	$2,854
		Three-Phase Customers	41,312	Customers	$61.01	$2,520	$2,970
	Transformer & Service						
		Single-Phase Customers	55,566	Customers	$232.99	$12,946	$15,257
		Three-Phase Customers	41,312	Customers	$317.24	$13,106	$15,445
FACILITIES	Feeder Backbone						
		Single-Phase Customers	114,442	kW, rateclass peak	$50.12	$5,736	$6,759
		Three-Phase Customers	208,280	kW, rateclass peak	$50.12	$10,439	$12,302
	Feeder Local Facilities						
		Single-Phase Customers	250,048	Design Demand	$78.67	$19,671	$23,182
		Three-Phase Customers	442,038	Design Demand	$21.01	$9,287	$10,945
DEMAND	Subtransmission		329,048	kW, rateclass peak	$1.33	$438	$516
	Substation		322,722	kW, rateclass peak	$15.88	$5,125	$6,039
SUBTOTAL						$81,691	$96,269
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	51	Customers	$50.04	$3	$3
		Three-Phase Customers	303	Customers	$100.38	$30	$36
	Transformer & Service						
		Single-Phase Customers	51	Customers	$224.52	$11	$13
		Three-Phase Customers	303	Customers	$745.21	$226	$266
FACILITIES	Feeder Backbone						
		Single-Phase Customers	389	kW, rateclass peak	$52.07	$20	$24
		Three-Phase Customers	7,670	kW, rateclass peak	$52.07	$399	$471
	Feeder Local Facilities						
		Single-Phase Customers	2,147	Design Demand	$93.12	$200	$236
		Three-Phase Customers	30,785	Design Demand	$23.35	$719	$847
DEMAND	Subtransmission		8,217	kW, rateclass peak	$1.33	$11	$13
	Substation		8,059	kW, rateclass peak	$15.88	$128	$151
SUBTOTAL						$1,748	$2,059
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	248	Customers	$50.54	$13	$15
		Three-Phase Customers	2,570	Customers	$70.05	$180	$212
	Transformer & Service						
		Single-Phase Customers	248	Customers	$34.20	$8	$10
		Three-Phase Customers	2,570	Customers	$50.84	$131	$154
FACILITIES	Feeder Backbone						
		Single-Phase Customers	722	kW, rateclass peak	$50.12	$36	$43
		Three-Phase Customers	11,115	kW, rateclass peak	$50.12	$557	$657
	Feeder Local Facilities						
		Single-Phase Customers	2,579	Design Demand	$73.97	$191	$225
		Three-Phase Customers	40,349	Design Demand	$19.75	$797	$939
DEMAND	Subtransmission		12,069	kW, rateclass peak	$1.33	$16	$19
	Substation		11,837	kW, rateclass peak	$15.88	$188	$222
SUBTOTAL						$2,117	$2,494

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2024

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 49 Irrigation & Drainage Service - > 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	14	Customers	$50.54	$1	$1
		Three-Phase Customers	1,268	Customers	$60.83	$77	$91
	Transformer & Service						
		Single-Phase Customers	14	Customers	$317.26	$4	$5
		Three-Phase Customers	1,268	Customers	$317.27	$402	$474
FACILITIES	Feeder Backbone						
		Single-Phase Customers	417	kW, rateclass peak	$52.07	$22	$26
		Three-Phase Customers	37,742	kW, rateclass peak	$52.07	$1,965	$2,316
	Feeder Local Facilities						
		Single-Phase Customers	517	Design Demand	$89.70	$46	$55
		Three-Phase Customers	70,628	Design Demand	$22.49	$1,588	$1,872
DEMAND	Subtransmission		38,906	kW, rateclass peak	$1.33	$52	$61
	Substation		38,159	kW, rateclass peak	$15.88	$606	$714
SUBTOTAL						$4,764	$5,614
Schedule 83 General Service (31-200 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	893	Customers	$50.54	$45	$53
		Three-Phase Customers	10,846	Customers	$105.82	$1,148	$1,353
	Transformer & Service						
		Single-Phase Customers	893	Customers	$516.67	$461	$544
		Three-Phase Customers	10,846	Customers	$1,282.21	$13,907	$16,388
FACILITIES	Feeder Backbone						
		Single-Phase Customers	29,316	kW, rateclass peak	$52.07	$1,526	$1,799
		Three-Phase Customers	576,766	kW, rateclass peak	$52.07	$30,032	$35,392
	Feeder Local Facilities						
		Single-Phase Customers	49,735	Design Demand	$93.12	$4,631	$5,458
		Three-Phase Customers	979,371	Design Demand	$23.35	$22,868	$26,950
DEMAND	Subtransmission		617,961	kW, rateclass peak	$1.33	$822	$969
	Substation		606,082	kW, rateclass peak	$15.88	$9,625	$11,342
SUBTOTAL						$85,065	$100,247
Schedule 85 General Service (201-4,000 kW)							
CUSTOMER	Meters						
		Secondary Customers	1,457	Customers	$113.81	$166	$195
		Primary Customers	218	Customers	$1,795.89	$392	$461
	Transformer & Service						
		Secondary Customers	1,457	Customers	$2,893.64	$4,216	$4,968
		Primary Customers	218	Customers	$0.00	$0	$0
FACILITIES	Feeder Backbone		622,090	kW, rateclass peak	$42.18	$26,240	$30,923
	Feeder Local Facilities		952,908	Design Demand	$7.37	$7,023	$8,276
DEMAND	Subtransmission		634,283	kW, rateclass peak	$1.33	$844	$994
	Substation		622,090	kW, rateclass peak	$15.88	$9,879	$11,642
SUBTOTAL						$48,758	$57,460

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2024

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 89 General Service (4,000 plus kW)							
CUSTOMER	Meters						
		Secondary Meters	0	Customers	$113.96	$0	$0
		Primary Meters	43	Customers	$1,896.75	$82	$96
		Substation Meters	7	Customers	$17,623.44	$123	$145
	Transformer & Service						
		Secondary Customers	0	Customers	$17,546.57	$0	$0
		Primary Customers	43	Customers	$0.00	$0	$0
FACILITIES	Feeder Backbone						
		Secondary Customers	0	Customers	$104,332.00	$0	$0
		Primary Customers	43	Customers	$104,332.00	$4,486	$5,287
		Subtransmission 115 kV Feeder	7	Customers	$93,301.00	$653	$770
DEMAND	Subtransmission		445,376	kW, rateclass peak	$1.33	$592	$698
	Substation (Sec. & Prim. Only)		387,580	kW, rateclass peak	$15.88	$6,155	$7,253
SUBTOTAL						$12,091	$14,249
Schedule 90 Primary Voltage Service							
CUSTOMER	Meters						
		Primary Meters	6	Customers	$1,896.75	$11	$13
FACILITIES	Feeder Backbone						
		Primary Customers	6	Customers	$491,171.00	$2,947	$3,473
DEMAND	Subtransmission		445,466	kW, rateclass peak	$1.33	$592	$698
	Substation (Sec. & Prim. Only)		436,903	kW, rateclass peak	$15.88	$6,938	$8,176
SUBTOTAL						$10,489	$12,361
Schedules 91 & 95 Streetlighting & Highway Lighting							
CUSTOMER	Customer Service		149,187	Lights	$1.32	$197	$232
	Transformer & Service		149,187	Lights	$3.28	$489	$577
FACILITIES	Feeder Backbone		10,070	kW, rateclass peak	$43.88	$442	$521
	Feeder Local Facilities		10,070	Design Demand	$54.88	$553	$651
DEMAND	Subtransmission		10,267	kW, rateclass peak	$1.33	$14	$16
	Substation		10,070	kW, rateclass peak	$15.88	$160	$188
FIXED	Luminaires & Poles						**$8,077**
SUBTOTAL						$1,854	$10,263

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2024

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 92 Traffic Signals						
CUSTOMER	Transformer & Service	1,248	Intersections	$6.33	$8	$9
FACILITIES	Feeder Backbone	318	kW, rateclass peak	$43.89	$14	$16
	Feeder Local Facilities	318	Design Demand	$19.25	$6	$7
DEMAND	Subtransmission	324	kW, rateclass peak	$1.33	$0	$1
	Substation	318	kW, rateclass peak	$15.88	$5	$6
SUBTOTAL					$33	$39
Summary						
CUSTOMER	Meters	942,011	Customers		$24,650	$29,049
	Transformer & Service		Customers		$142,273	$167,663
	Customer Service	170,218	Lights		$225	$265
FACILITIES	Feeder Backbone	3,649,489	kW, rateclass peak		$168,356	$198,402
	Feeder Local Facilities	6,143,699	Design Demand		$240,147	$283,005
DEMAND	Subtransmission	4,611,860	kW, rateclass peak		$6,134	$7,228
	Substation	4,473,972	kW rateclass peak		$71,047	$83,726
FIXED	Luminaires & Poles					$10,383
TOTALS					$652,830	$779,721
					TARGET	$779,721
				EQUAL PERCENT		117.85%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2024

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	827,209	$0.24	$199	$2,406
Three Phase	0	$0.24	$0	$0
Schedule 15				
Residential	3,789	$0.00	$0	$0
Commercial	4,928	$0.00	$0	$0
Schedule 32				
Single Phase	55,566	$0.52	$29	$350
Three Phase	41,312	$0.52	$21	$260
Schedule 38				
Single Phase	51	$2.72	$0	$2
Three Phase	303	$2.72	$1	$10
Schedule 47				
Single Phase	248	$1.12	$0	$3
Three Phase	2,570	$1.12	$3	$35
Schedule 49				
Single Phase	14	$1.64	$0	$0
Three Phase	1,268	$1.64	$2	$25
Schedule 83				
Single Phase	893	$1.50	$1	$16
Three Phase	10,846	$1.50	$16	$197
Schedule 85				
Secondary	1,457	$2.75	$4	$49
Primary	218	$2.75	$1	$7
Schedule 89				
Secondary	0	$0.38	$0	$0
Primary	43	$0.38	$0	$0
Subtransmission	7	$0.38	$0	$0
Schedule 90-P	6	$0.15	$0	$0
Schedules 91/95	186	$0.00	$0	$0
Schedule 92	16	$0.00	$0	$0
TOTAL	950,930		$277	$3,361
			TARGET	$3,361
		EQUAL PERCENT		1212%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2024

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	827,209	$31.40	$25,974	$37,528
Three Phase	0	$31.40	$0	$0
Schedule 15				
Residential	3,789	$2.15	$8	$12
Commercial	4,928	$1.80	$9	$13
Schedule 32				
Single Phase	55,566	$29.52	$1,640	$2,370
Three Phase	41,312	$29.52	$1,220	$1,762
Schedule 38				
Single Phase	51	$225.19	$11	$17
Three Phase	303	$225.19	$68	$99
Schedule 47				
Single Phase	248	$28.01	$7	$10
Three Phase	2,570	$28.01	$72	$104
Schedule 49				
Single Phase	14	$228.34	$3	$5
Three Phase	1,268	$228.34	$290	$418
Schedule 83				
Single Phase	893	$232.19	$207	$300
Three Phase	10,846	$232.19	$2,518	$3,638
Schedule 85				
Secondary	1,457	$230.87	$336	$486
Primary	218	$230.87	$50	$73
Schedule 89				
Secondary	0	$214.77	$0	$0
Primary	43	$214.77	$9	$13
Subtransmission	7	$214.77	$2	$2
Schedule 90-P	6	$216.19	$1	$2
Schedules 91/95	186	$213.87	$40	$57
Schedule 92	16	$191.99	$3	$4
TOTAL	950,930		$32,470	$46,912
			TARGET	$46,912
		EQUAL PERCENT		144%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2024

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	827,209	$18.98	$15,700	$108,543
Three Phase	0	$18.98	$0	$0
Schedule 15				
Residential	3,789	$0.00	$0	$0
Commercial	4,928	$0.00	$0	$0
Schedule 32				
Single Phase	55,566	$22.05	$1,225	$8,470
Three Phase	41,312	$22.05	$911	$6,298
Schedule 38				
Single Phase	51	$20.19	$1	$7
Three Phase	303	$20.19	$6	$42
Schedule 47				
Single Phase	248	$16.89	$4	$29
Three Phase	2,570	$16.89	$43	$300
Schedule 49				
Single Phase	14	$17.03	$0	$2
Three Phase	1,268	$17.03	$22	$149
Schedule 83				
Single Phase	893	$127.08	$113	$784
Three Phase	10,846	$127.08	$1,378	$9,529
Schedule 85				
Secondary	1,457	$1,231.29	$1,794	$12,403
Primary	218	$1,231.29	$268	$1,856
Schedule 89				
Secondary	0	$8,131.34	$0	$0
Primary	43	$8,131.34	$350	$2,417
Subtransmission	7	$8,131.34	$57	$394
Schedule 90-P	6	$34,804.47	$209	$1,444
Schedule 91/95	186	$0.00	$0	$0
Schedule 92	16	$6.05	$0	$1
TOTAL	950,930		$22,083	$152,667
			TARGET	$152,667
		EQUAL PERCENT		691%

PORTLAND GENERAL ELECTRIC

PROPOSED
Summary of Area and Streetlighting Revenue

Schedule 15 - Area Lighting	
Fixtures & Maintenance	$1,551,350
Poles	$754,738
Energy (volumetric c/kWh rate)	$1,754,928
Total	**$4,061,015**

Schedule 91/95 - Street and Highway Lighting	
Fixtures & Maintenance (Options A&B)	$4,743,787
Poles (Options A&B)	$3,333,431
Energy (volumetric c/kWh rate)	$5,144,159
Total	**$13,221,377**

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	$2.30	$0.99	$3.82	$4.12	$2.81	$1.82		-	-	-	0	0	$0	$0	$0
84	Cobrahead - PD	HPS	100-watt	43	Standard	$2.30	$0.99	$5.47	$4.91	$3.60	$2.61		-	4	4	8	4	$0	$48	$525
85	Cobrahead - PD	HPS	150-watt	62	Standard	$2.37	$0.99	$7.89	$6.13	$4.75	$3.76		-	-	-	0	0	$0	$0	$0
89	Cobrahead - PD	HPS	200-watt	79	Standard	$6.23	$1.03	$10.06	$11.02	$5.82	$4.79		-	2	-	2	2	$0	$25	$241
86	Cobrahead - PD	HPS	250-watt	102	Standard	$3.04	$1.03	$12.99	$9.22	$7.21	$6.18		-	-	-	0	0	$0	$0	$0
87	Cobrahead - PD	HPS	400-watt	163	Standard	$3.36	$1.05	$20.75	$13.24	$10.93	$9.88		-	1	1	2	4	$0	$13	$498
33	Cobrahead	HPS	70-watt	30	Standard	$6.16	$1.29	$3.82	$7.98	$3.11	$1.82		1	34	309	344	124	$74	$526	$15,769
34	Cobrahead	HPS	100-watt	43	Standard	$5.29	$1.19	$5.47	$7.90	$3.80	$2.61		10	659	161	830	428	$635	$9,411	$54,481
35	Cobrahead	HPS	150-watt	62	Standard	$5.38	$1.20	$7.89	$9.14	$4.96	$3.76		-	140	197	337	251	$0	$2,016	$31,907
39	Cobrahead	HPS	200-watt	79	Standard	$5.89	$1.26	$10.06	$10.68	$6.05	$4.79		10	710	303	1,023	970	$707	$10,735	$123,497
36	Cobrahead	HPS	250-watt	102	Standard	$5.43	$1.21	$12.99	$11.61	$7.39	$6.18		5	496	128	629	770	$326	$7,202	$98,049
37	Cobrahead	HPS	400-watt	163	Standard	$5.65	$1.23	$20.75	$15.53	$11.11	$9.88		160	75	154	389	761	$10,848	$1,107	$96,861
31	Flood	HPS	250-watt	102	Standard	$7.46	$1.43	$12.99	$13.64	$7.61	$6.18		72	1	2	75	92	$6,445	$17	$11,691
32	Flood	HPS	400-watt	163	Standard	$7.46	$1.43	$20.75	$17.34	$11.31	$9.88		180	8	17	205	401	$16,114	$137	$51,045
40	Post-Top	HPS	100-watt	43	Standard	$6.88	$1.38	$5.47	$9.49	$3.99	$2.61		265	1,658	343	2,266	1,169	$21,878	$27,456	$148,740
76	Shoebox	HPS	70-watt	30	Standard	$5.91	$1.27	$3.82	$7.73	$3.09	$1.82		1	66	14	81	29	$71	$1,006	$3,713
77	Shoebox	HPS	100-watt	43	Standard	$6.51	$1.34	$5.47	$9.12	$3.95	$2.61		-	625	1,312	1,937	999	$0	$10,050	$127,145
78	Shoebox	HPS	150-watt	62	Standard	$6.98	$1.39	$7.89	$10.74	$5.15	$3.76		-	57	85	142	106	$0	$951	$13,445
81	Special Acorn	HPS	100-watt	43	Custom	$11.38	$1.90	$5.47	$13.99	$4.51	$2.61		13	977	241	1,231	635	$1,775	$22,276	$80,803
82	Victorian	HPS	150-watt	62	Custom	$11.39	$1.91	$7.89	$15.15	$5.67	$3.76		5	583	211	799	594	$683	$13,362	$75,649
49	Victorian	HPS	200-watt	79	Custom	$9.81	$1.73	$10.06	$14.60	$6.52	$4.79		3	80	3	86	82	$353	$1,661	$10,382
83	Victorian	HPS	250-watt	102	Custom	$9.73	$1.72	$12.99	$15.91	$7.90	$6.18		67	688	12	767	939	$7,823	$14,200	$119,560
64	Capitol Acorn	HPS	100-watt	43	Custom	$13.87	$2.19	$5.47	$16.48	$4.80	$2.61		4	13	7	24	12	$666	$342	$1,575
67	Capitol Acorn	HPS	150-watt	62	Custom	$13.45	$2.14	$7.89	$17.21	$5.90	$3.76		-	363	28	391	291	$0	$9,322	$37,020
65	Capitol Acorn	HPS	200-watt	79	Custom	$14.16	$2.22	$10.06	$18.95	$7.01	$4.79		-	61	-	61	58	$0	$1,625	$7,364
66	Capitol Acorn	HPS	250-watt	102	Custom	$13.45	$2.14	$12.99	$19.63	$8.32	$6.18		-	-	-	0	0	$0	$0	$0
12	Acorn - Indep.	HPS	100-watt	43	Custom	$10.88	$1.82	$5.47	$13.49	$4.43	$2.61		-	1	22	23	12	$0	$22	$1,510
13	Acorn - Indep.	HPS	150-watt	62	Custom	$9.34	$1.65	$7.89	$13.10	$5.41	$3.76		-	-	8	8	6	$0	$0	$757
98	Techtra	HPS	100-watt	43	Custom	$18.06	$2.63	$5.47	$20.67	$5.24	$2.61		-	31	-	31	16	$0	$978	$2,035
99	Techtra	HPS	150-watt	62	Custom	$18.92	$2.73	$7.89	$22.68	$6.49	$3.76		1	175	4	180	134	$227	$5,733	$17,042
88	Techtra	HPS	250-watt	102	Custom	$18.00	$2.63	$12.99	$24.18	$8.81	$6.18		-	-	-	0	0	$0	$0	$0
90	Westbrooke Acorn	HPS	70-watt	30	Custom	$13.01	$2.06	$3.82	$14.83	$3.88	$1.82		1	44	-	45	16	$156	$1,088	$2,063
91	Westbrooke Acorn	HPS	100-watt	43	Custom	$13.29	$2.09	$5.47	$15.90	$4.70	$2.61		31	410	11	452	233	$4,944	$10,283	$29,669
92	Westbrooke Acorn	HPS	150-watt	62	Custom	$16.32	$2.43	$7.89	$20.08	$6.19	$3.76		-	58	-	58	43	$0	$1,691	$5,491
93	Westbrooke Acorn	HPS	200-watt	79	Custom	$4.38	$1.09	$10.06	$9.17	$5.88	$4.79		-	2	-	2	2	$0	$26	$241
94	Westbrooke Acorn	HPS	250-watt	102	Custom	$11.66	$1.90	$12.99	$17.84	$8.08	$6.18		57	30	-	87	106	$7,975	$684	$13,562
62	Cobrahead	MH	150-watt	60	Custom	$7.69	$1.51	$7.64	$11.33	$5.15	$3.64		-	-	28	28	20	$0	$0	$2,567
61	Flood	MH	350-watt	139	Custom	$8.72	$1.60	$17.70	$17.14	$10.02	$8.42		-	-	-	0	0	$0	$0	$0
47	Flood	HPS	750-watt	285	Custom	$10.88	$2.14	$36.28	$28.15	$19.41	$17.27		49	-	-	49	168	$6,397	$0	$21,333
18	Ornamental Acorn Twin / Opt C	QL	85-watt	64	Custom	$0.12	$0.12	$8.15	$4.00	$4.00	$3.88		-	-	445	445	342	$0	$0	$43,521
20	Ornamental Acorn / Opt C	QL	55-watt	21	Custom	$0.12	$0.12	$2.67	$1.39	$1.39	$1.27		-	-	2	2	1	$0	$0	$64
26	Ornamental Acorn Twin / Opt C	QL	55-watt	42	Custom	$0.12	$0.12	$5.35	$2.67	$2.67	$2.55		-	-	15	15	8	$0	$0	$963
44	Composite Twin / Opt C	Comp	140-watt	54	Custom	$0.12	$0.12	$6.87	$3.39	$3.39	$3.27		-	-	41	41	27	$0	$0	$3,380
45	Composite Twin / Opt C	Comp	175-watt	66	Custom	$0.12	$0.12	$8.40	$4.12	$4.12	$4.00		-	-	100	100	79	$0	$0	$10,080
19	Cobrahead - (C) Only	MV	100-watt	39	Obsolete	$0.12	$0.12	$4.97	$2.48	$2.48	$2.36		-	-	1	1	0	$0	$0	$60
21	Cobrahead	MV	175-watt	66	Obsolete	$5.13	$1.18	$8.40	$9.13	$5.18	$4.00		6	99	68	173	137	$369	$1,402	$17,438
22	Cobrahead	MV	250-watt	94	Obsolete	$3.29	$0.12	$11.97	$8.99	$5.82	$5.70		-	-	23	23	26	$0	$0	$3,304
23	Cobrahead	MV	400-watt	147	Obsolete	$5.35	$1.22	$18.71	$14.26	$10.13	$8.91		18	14	75	107	189	$1,156	$205	$24,024
24	Cobrahead	MV	1,000-watt	374	Obsolete	$5.98	$1.33	$47.61	$28.64	$23.99	$22.66		5	1	3	9	40	$359	$16	$5,142
9	Mongoose	HPS	150-watt	62	Obsolete	$12.23	$1.99	$7.89	$15.99	$5.75	$3.76		-	10	-	10	7	$0	$239	$947
10	Mongoose	HPS	250-watt	102	Obsolete	$11.62	$2.02	$12.99	$17.80	$8.20	$6.18		-	8	-	8	10	$0	$194	$1,247
50	Special Box - Space-Glo	HPS	70-watt	30	Obsolete	$5.77	$1.27	$3.82	$7.59	$3.09	$1.82		-	-	-	0	0	$0	$0	$0
46	Special Box - Space-Glo	MV	175-watt	66	Obsolete	$5.75	$1.27	$8.40	$9.75	$5.27	$4.00		2	113	23	138	109	$138	$1,722	$13,910
51	Box - Gardco Hub / Opt C	HPS	Twin 70-watt	60	Obsolete	$0.12	$0.12	$7.64	$3.76	$3.76	$3.64		-	-	-	0	0	$0	$0	$0
52	Box - Gardco Hub / Opt C	HPS	70-watt	30	Obsolete	$0.12	$0.12	$3.82	$1.94	$1.94	$1.82		-	-	30	30	11	$0	$0	$1,375
53	Box - Gardco Hub	HPS	100-watt	43	Obsolete	$4.94	$1.57	$5.47	$7.55	$4.18	$2.61		-	2	-	2	1	$0	$38	$131
54	Box - Gardco Hub	HPS	150-watt	62	Obsolete	$1.03	$1.03	$7.89	$4.79	$4.79	$3.76		-	-	14	14	10	$0	$0	$1,326
55	Box - Gardco Hub / Opt C	HPS	250-watt	102	Obsolete	$0.12	$0.12	$12.99	$6.30	$6.30	$6.18		-	-	3	3	4	$0	$0	$468
56	Box - Gardco Hub / Opt C	HPS	400-watt	163	Obsolete	$0.12	$0.12	$20.75	$10.00	$10.00	$9.88		-	-	-	0	0	$0	$0	$0
58	Box - Gardco Hub	MH	250-watt	99	Obsolete	$1.07	$1.04	$12.60	$7.07	$7.04	$6.00		-	1	6	7	8	$0	$12	$1,058

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	DAX B	DAX C	DAX TOTAL	Proposed Sch 91 & 95 A & B Counts A	Counts B	Counts C	Counts TOTAL	Annual MWh	Annual Fixed Revenue A	Annual Fixed Revenue B	Annual Energy
59	Box - Gardco Hub	MH	400-watt	156	Obsolete	$1.07	$1.04	$19.86	$10.52	$10.49	$9.45		-	2	-	2	4	$0	$25	$477
48	Cobrahead	MH	175-watt	71	Obsolete	$2.66	$1.28	$9.04	$6.96	$5.58	$4.30		-	-	22	22	19	$0	$0	$2,387
60	Flood	MH	400-watt	156	Obsolete	$5.89	$1.31	$19.86	$15.34	$10.76	$9.45		6	-	10	16	30	$424	$0	$3,813
69	Cobrahead DW 70/100	HPS	100-watt	43	Obsolete	$1.03	$1.03	$5.47	$3.64	$3.64	$2.61		-	-	-	0	0	$0	$0	$0
70	Cobrahead DW 100/150	HPS	100-watt	43	Obsolete	$1.03	$1.03	$5.47	$3.64	$3.64	$2.61		-	-	-	0	0	$0	$0	$0
71	Cobrahead DW 100/150	HPS	150-watt	62	Obsolete	$1.03	$1.03	$7.89	$4.79	$4.79	$3.76		-	-	-	0	0	$0	$0	$0
2	Victorian	QL	85-watt	32	Obsolete	$0.36	$0.36	$4.07	$2.30	$2.30	$1.94		-	-	326	326	125	$0	$0	$15,922
1	Victorian	QL	165-watt	60	Obsolete	$13.99	$0.93	$7.64	$17.63	$4.57	$3.64		-	-	220	220	158	$0	$0	$20,170
3	Techtra	QL	165-watt	60	Obsolete	$20.66	$1.21	$7.64	$24.30	$4.85	$3.64		-	-	4	4	3	$0	$0	$367
95	KIM SBC Shoebox	HPS	150-watt	62	Obsolete	$1.03	$1.03	$7.89	$4.79	$4.79	$3.76		-	28	65	93	69	$0	$346	$8,805
96	KIM Archetype	HPS	250-watt	102	Obsolete	$11.77	$2.04	$12.99	$17.95	$8.22	$6.18		-	62	20	82	100	$0	$1,518	$12,782
97	KIM Archetype	HPS	400-watt	163	Obsolete	$14.89	$2.44	$20.75	$24.77	$12.32	$9.88		-	16	28	44	86	$0	$468	$10,956
80	Acorn Type	HPS	70-watt	30	Obsolete	$8.48	$1.64	$3.82	$10.30	$3.46	$1.82		1	10	-	11	4	$102	$197	$504
73	GardCo Bronze - (C) Only	HPS	70-watt	30	Obsolete	$0.12	$0.12	$3.82	$1.94	$1.94	$1.82		-	-	5	5	2	$0	$0	$229
72	GardCo Bronze - (C) Only	MV	175-watt	66	Obsolete	$0.12	$0.12	$8.40	$4.12	$4.12	$4.00		-	-	1	1	1	$0	$0	$101
25	Post-Top - Black	HPS	70-watt	30	Obsolete	$4.96	$1.17	$3.82	$6.78	$2.99	$1.82		38	365	4	407	147	$2,262	$5,125	$18,657
43	Rect.Type - (C) Only	HPS	200-watt	79	Obsolete	$0.12	$0.12	$10.06	$4.91	$4.91	$4.79		-	-	16	16	15	$0	$0	$1,932
5	Incand. - (C) Only	IND	92-watt	31	Obsolete	$0.12	$0.12	$3.95	$2.00	$2.00	$1.88		-	-	21	21	8	$0	$0	$995
6	Incand. - (C) Only	IND	182-watt	62	Obsolete	$0.12	$0.12	$7.89	$3.88	$3.88	$3.76		-	-	4	4	3	$0	$0	$379
29	Town and Country Post-Top	MV	175-watt	66	Obsolete	$5.37	$1.21	$8.40	$9.37	$5.21	$4.00		3	219	7	229	181	$193	$3,180	$23,083
27	Flood	HPS	70-watt	30	Obsolete	$5.42	$1.21	$3.82	$7.24	$3.03	$1.82		1	-	-	1	0	$65	$0	$46
30	Flood	HPS	100-watt	43	Obsolete	$5.18	$1.19	$5.47	$7.79	$3.80	$2.61		34	2	-	36	19	$2,113	$29	$2,363
38	Flood	HPS	200-watt	79	Obsolete	$5.81	$1.28	$10.06	$10.60	$6.07	$4.79		112	6	3	121	115	$7,809	$92	$14,607
41	Cobrahead - PD	HPS	310-watt	124	Obsolete	$6.32	$1.37	$15.79	$13.83	$8.88	$7.51		-	-	-	0	0	$0	$0	$0
14	Ornamental - (C) Only	HPS	100-watt	43	Obsolete	$0.12	$0.12	$5.47	$2.73	$2.73	$2.61		-	-	84	84	43	$0	$0	$5,514
15	Twin Ornamental -(C) Only	HPS	Twin 100-watt	86	Obsolete	$0.12	$0.12	$10.95	$5.33	$5.33	$5.21		-	-	2	2	2	$0	$0	$263
7	Flourescent - (C) Only	FLR	28-watt	12	Obsolete	$0.12	$0.12	$1.53	$0.85	$0.85	$0.73		-	-	9	9	1	$0	$0	$165
100	Cobrahead	LED	>30W-35W	11	Standard	$5.54	$0.43	$1.40	$6.21	$1.10	$0.67		1,653	194	-	1,847	244	$109,891	$1,001	$31,030
101	Cobrahead	LED	>45W-50W	16	Standard	$5.39	$0.43	$2.04	$6.36	$1.40	$0.97		23,844	1	-	23,845	4,578	$1,542,230	$5	$583,726
102	Cobrahead	LED	>50W-55W	18	Standard	$5.67	$0.43	$2.29	$6.76	$1.52	$1.09		2,133	2,623	-	4,756	1,027	$145,129	$13,535	$130,695
103	Cobrahead	LED	>65W-70W	23	Standard	$6.07	$0.44	$2.93	$7.46	$1.83	$1.39		4,999	-	-	4,999	1,380	$364,127	$0	$175,765
104	Cobrahead	LED	>100W-110W	36	Standard	$6.31	$0.45	$4.58	$8.49	$2.63	$2.18		1,679	542	-	2,221	959	$127,134	$2,927	$122,066
105	Cobrahead	LED	>130W-140W	46	Standard	$7.04	$0.46	$5.86	$9.83	$3.25	$2.79		67	-	-	67	37	$5,660	$0	$4,711
107	Cobrahead	LED	>170W-180W	60	Standard	$8.30	$0.49	$7.64	$11.94	$4.13	$3.64		171	-	-	171	123	$17,032	$0	$15,677
108	Cobrahead	LED	>190W-200W	67	Standard	$8.26	$0.49	$8.53	$12.32	$4.55	$4.06		159	380	-	539	433	$15,760	$2,234	$55,172
109	Cobrahead	LED	>20W-25W	8	Standard	$5.17	$0.42	$1.02	$5.65	$0.90	$0.48		-	-	-	0	0	$0	$0	$0
132	Cobrahead	LED	>150W-160W	53	Standard	$8.39	$0.49	$6.75	$11.60	$3.70	$3.21		750	1,003	30	1,783	1,134	$75,510	$5,898	$144,423
133	Cobrahead	LED	>25W-30W	9	Standard	$5.17	$0.42	$1.15	$5.72	$0.97	$0.55		4,812	232	188	5,232	565	$298,536	$1,169	$72,202
134	Cobrahead	LED	>40W-45W	15	Standard	$5.35	$0.43	$1.91	$6.26	$1.34	$0.91		1,748	303	23	2,074	373	$112,222	$1,563	$47,536
135	Cobrahead	LED	>85W-90W	30	Standard	$6.09	$0.44	$3.82	$7.91	$2.26	$1.82		1,641	707	64	2,412	868	$119,924	$3,733	$110,566
200	Cobrahead	LED	>35W-40W	13	Standard	$5.17	$0.42	$1.66	$5.96	$1.21	$0.79		-	-	-	0	0	$0	$0	$0
201	Cobrahead	LED	>55W-60W	20	Standard	$5.35	$0.43	$2.55	$6.56	$1.64	$1.21		-	-	-	0	0	$0	$0	$0
202	Cobrahead	LED	>60W-65W	21	Standard	$5.35	$0.43	$2.67	$6.62	$1.70	$1.27		-	-	-	0	0	$0	$0	$0
203	Cobrahead	LED	>70W-75W	25	Standard	$6.09	$0.44	$3.18	$7.61	$1.96	$1.52		-	-	-	0	0	$0	$0	$0
204	Cobrahead	LED	>75W-80W	26	Standard	$6.09	$0.44	$3.31	$7.67	$2.02	$1.58		-	-	-	0	0	$0	$0	$0
205	Cobrahead	LED	>80W-85W	28	Standard	$6.09	$0.44	$3.56	$7.79	$2.14	$1.70		-	-	-	0	0	$0	$0	$0
206	Cobrahead	LED	>90W-95W	32	Standard	$6.09	$0.44	$4.07	$8.03	$2.38	$1.94		-	-	-	0	0	$0	$0	$0
207	Cobrahead	LED	>95W-100W	33	Standard	$6.09	$0.44	$4.20	$8.09	$2.44	$2.00		-	-	-	0	0	$0	$0	$0
208	Cobrahead	LED	>110W-120W	39	Standard	$6.09	$0.44	$4.97	$8.45	$2.80	$2.36		-	-	-	0	0	$0	$0	$0
209	Cobrahead	LED	>120W-130W	43	Standard	$6.09	$0.44	$5.47	$8.70	$3.05	$2.61		-	-	-	0	0	$0	$0	$0
210	Cobrahead	LED	>140W-150W	50	Standard	$8.39	$0.49	$6.37	$11.42	$3.52	$3.03		-	-	-	0	0	$0	$0	$0
211	Cobrahead	LED	>160W-170W	56	Standard	$8.39	$0.49	$7.13	$11.78	$3.88	$3.39		-	-	-	0	0	$0	$0	$0
212	Cobrahead	LED	>180W-190W	63	Standard	$8.39	$0.49	$8.02	$12.21	$4.31	$3.82		-	-	-	0	0	$0	$0	$0
110	Acorn	LED	>45W-50W	16	Custom	$10.77	$0.54	$2.04	$11.74	$1.51	$0.97		252	46	-	298	57	$32,568	$298	$7,295
111	Acorn	LED	>65W-70W	23	Custom	$12.93	$0.58	$2.93	$14.32	$1.97	$1.39		235	129	-	364	100	$36,463	$898	$12,798
137	Acorn	LED	>35W-40W	13	Custom	$13.32	$0.59	$1.66	$14.11	$1.38	$0.79		1	-	-	1	0	$160	$0	$20
138	Acorn	LED	>55W-60W	20	Custom	$13.32	$0.59	$2.55	$14.53	$1.80	$1.21		1,040	16	954	2,010	482	$166,234	$113	$61,506
139	Acorn	LED	>70W-75W	25	Custom	$13.32	$0.59	$3.18	$14.84	$2.11	$1.52		111	32	5	148	44	$17,742	$227	$5,648
213	Acorn	LED	>40W-45W	15	Custom	$13.32	$0.59	$1.91	$14.23	$1.50	$0.91		-	-	-	0	0	$0	$0	$0
214	Acorn	LED	>50W-55W	18	Custom	$13.32	$0.59	$2.29	$14.41	$1.68	$1.09		-	-	-	0	0	$0	$0	$0

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
215	Acorn	LED	>60W-65W	21	Custom	$13.32	$0.59	$2.67	$14.59	$1.86	$1.27		-	-	-	0	0	$0	$0	$0
112	Pendant (non-flared)	LED	53	18	Custom	$16.33	$0.65	$2.29	$17.42	$1.74	$1.09		62	-	-	62	13	$12,150	$0	$1,704
113	Pendant (non-flared)	LED	69	24	Custom	$16.07	$0.64	$3.06	$17.52	$2.09	$1.45		-	-	-	0	0	$0	$0	$0
114	Pendant (non-flared)	LED	85	29	Custom	$16.69	$0.66	$3.69	$18.45	$2.42	$1.76		2	-	-	2	1	$401	$0	$89
117	Pendant (flared)	LED	>50W-55W	18	Custom	$17.49	$0.67	$2.29	$18.58	$1.76	$1.09		1,074	2	143	1,219	263	$225,411	$16	$33,498
118	Pendant (flared)	LED	>65W-70W	23	Custom	$16.58	$0.65	$2.93	$17.97	$2.04	$1.39		48	1	38	87	24	$9,550	$8	$3,059
119	Pendant (flared)	LED	>80W-85W	28	Custom	$16.81	$0.66	$3.56	$18.51	$2.36	$1.70		9	-	-	9	3	$1,815	$0	$384
127	Pendant (non-flare)	LED	36	12	Custom	$15.08	$0.62	$1.53	$15.81	$1.35	$0.73		6	4	-	10	1	$1,086	$30	$184
128	Pendant (flare)	LED	>35W-40W	13	Custom	$14.67	$0.62	$1.66	$15.46	$1.41	$0.79		1,025	95	-	1,120	175	$180,441	$707	$22,310
216	Pendant (flare)	LED	>40W-45W	15	Standard	$14.67	$0.62	$1.91	$15.58	$1.53	$0.91		-	-	-	0	0	$0	$0	$0
217	Pendant (flare)	LED	>45W-50W	16	Standard	$14.67	$0.62	$2.04	$15.64	$1.59	$0.97		-	-	-	0	0	$0	$0	$0
218	Pendant (flare)	LED	>55W-60W	20	Standard	$17.49	$0.67	$2.55	$18.70	$1.88	$1.21		4	-	-	4	1	$840	$0	$122
219	Pendant (flare)	LED	>60W-65W	21	Standard	$17.49	$0.67	$2.67	$18.76	$1.94	$1.27		-	-	-	0	0	$0	$0	$0
220	Pendant (flare)	LED	>70W-75W	25	Standard	$16.58	$0.65	$3.18	$18.10	$2.17	$1.52		21	-	-	21	6	$4,178	$0	$801
221	Pendant (flare)	LED	>75W-80W	26	Standard	$16.81	$0.66	$3.31	$18.39	$2.24	$1.58		-	-	-	0	0	$0	$0	$0
222	CREE XSP	LED	>30W-35W	11	Standard	$5.32	$0.43	$1.40	$5.99	$1.10	$0.67		-	-	-	0	0	$0	$0	$0
223	CREE XSP	LED	>65W-70W	23	Standard	$5.90	$0.44	$2.93	$7.29	$1.83	$1.39		-	-	-	0	0	$0	$0	$0
224	CREE XSP	LED	>130W-140W	46	Standard	$7.34	$0.47	$5.86	$10.13	$3.26	$2.79		-	-	-	0	0	$0	$0	$0
129	Post-Top, American Revolution	LED	>30W-35W	11	Custom	$8.12	$0.48	$1.40	$8.79	$1.15	$0.67		7,513	429	1,007	8,949	1,181	$732,067	$2,471	$150,343
130	Post-Top, American Revolution	LED	>45W-50W	16	Custom	$8.12	$0.48	$2.04	$9.09	$1.45	$0.97		98	1	-	99	19	$9,549	$6	$2,424
131	HADCO Acorn	LED	70	24	Custom	$17.42	$0.67	$3.06	$18.87	$2.12	$1.45		262	-	-	262	75	$54,768	$0	$9,621
141	Flood	LED	>120W-130W	43	Standard	$7.92	$0.48	$5.47	$10.53	$3.09	$2.61		43	1	-	44	23	$4,087	$6	$2,888
142	Flood	LED	>180W-190W	63	Standard	$9.15	$0.50	$8.02	$12.97	$4.32	$3.82		97	-	-	97	73	$10,651	$0	$9,335
143	Flood	LED	>370W-380W	127	Standard	$13.66	$0.60	$16.17	$21.36	$8.30	$7.70		9	-	-	9	14	$1,475	$0	$1,746
144	Flood	LED	>80W-85W	28	Standard	$7.37	$0.47	$3.56	$9.07	$2.17	$1.70		3	-	-	3	1	$265	$0	$128
145	5 - 10	LED		3		$0.00	$0.00	$0.38	$0.00	$0.00	$0.18		-	-	4	4	0	$0	$0	$18
146	>10 - 15	LED		4		$0.00	$0.00	$0.51	$0.00	$0.00	$0.24		-	-	-	0	0	$0	$0	$0
147	>15 - 20	LED		6		$0.00	$0.00	$0.76	$0.00	$0.00	$0.36		-	-	16	16	1	$0	$0	$146
148	>20 - 25	LED		8		$0.00	$0.00	$1.02	$0.00	$0.00	$0.48		-	-	818	818	79	$0	$0	$10,012
149	>25 - 30	LED		9		$0.00	$0.00	$1.15	$0.00	$0.00	$0.55		-	-	27,720	27,720	2,994	$0	$0	$382,536
150	>30 - 35	LED		11		$0.00	$0.00	$1.40	$0.00	$0.00	$0.67		-	-	3,732	3,732	493	$0	$0	$62,698
151	>35 - 40	LED		13		$0.00	$0.00	$1.66	$0.00	$0.00	$0.79		-	-	4,356	4,356	680	$0	$0	$86,772
152	>40 - 45	LED		15		$0.00	$0.00	$1.91	$0.00	$0.00	$0.91		-	-	6,080	6,080	1,094	$0	$0	$139,354
153	>45 - 50	LED		16		$0.00	$0.00	$2.04	$0.00	$0.00	$0.97		-	-	1,892	1,892	363	$0	$0	$46,316
154	>50 - 55	LED		18		$0.00	$0.00	$2.29	$0.00	$0.00	$1.09		-	-	2,648	2,648	572	$0	$0	$72,767
155	>55 - 60	LED		20		$0.00	$0.00	$2.55	$0.00	$0.00	$1.21		-	-	1,926	1,926	462	$0	$0	$58,936
156	>60 - 65	LED		21		$0.00	$0.00	$2.67	$0.00	$0.00	$1.27		-	-	6,615	6,615	1,667	$0	$0	$211,945
157	>65 - 70	LED		23		$0.00	$0.00	$2.93	$0.00	$0.00	$1.39		-	-	1,146	1,146	316	$0	$0	$40,293
158	>70 - 75	LED		25		$0.00	$0.00	$3.18	$0.00	$0.00	$1.52		-	-	168	168	50	$0	$0	$6,411
159	>75 - 80	LED		26		$0.00	$0.00	$3.31	$0.00	$0.00	$1.58		-	-	209	209	65	$0	$0	$8,301
160	>80 - 85	LED		28		$0.00	$0.00	$3.56	$0.00	$0.00	$1.70		-	-	1,634	1,634	549	$0	$0	$69,804
161	>85 - 90	LED		30		$0.00	$0.00	$3.82	$0.00	$0.00	$1.82		-	-	3,690	3,690	1,328	$0	$0	$169,150
162	>90 - 95	LED		32		$0.00	$0.00	$4.07	$0.00	$0.00	$1.94		-	-	184	184	71	$0	$0	$8,987
163	>95 - 100	LED		33		$0.00	$0.00	$4.20	$0.00	$0.00	$2.00		-	-	190	190	75	$0	$0	$9,576
164	>100 - 110	LED		36		$0.00	$0.00	$4.58	$0.00	$0.00	$2.18		-	-	867	867	375	$0	$0	$47,650
165	>110 - 120	LED		39		$0.00	$0.00	$4.97	$0.00	$0.00	$2.36		-	-	134	134	63	$0	$0	$7,992
166	>120 - 130	LED		43		$0.00	$0.00	$5.47	$0.00	$0.00	$2.61		-	-	86	86	44	$0	$0	$5,645
167	>130 - 140	LED		46		$0.00	$0.00	$5.86	$0.00	$0.00	$2.79		-	-	2,478	2,478	1,368	$0	$0	$174,253
168	>140 - 150	LED		50		$0.00	$0.00	$6.37	$0.00	$0.00	$3.03		-	-	195	195	117	$0	$0	$14,906
169	>150 - 160	LED		53		$0.00	$0.00	$6.75	$0.00	$0.00	$3.21		-	-	484	484	308	$0	$0	$39,204
170	>160 - 170	LED		56		$0.00	$0.00	$7.13	$0.00	$0.00	$3.39		-	-	158	158	106	$0	$0	$13,518
171	>170 - 180	LED		60		$0.00	$0.00	$7.64	$0.00	$0.00	$3.64		-	-	92	92	66	$0	$0	$8,435
172	>180 - 190	LED		63		$0.00	$0.00	$8.02	$0.00	$0.00	$3.82		-	-	918	918	694	$0	$0	$88,348
173	>190 - 200	LED		67		$0.00	$0.00	$8.53	$0.00	$0.00	$4.06		-	-	64	64	51	$0	$0	$6,551
174	>200 - 210	LED		70		$0.00	$0.00	$8.91	$0.00	$0.00	$4.24		-	-	29	29	24	$0	$0	$3,101
175	>210 - 220	LED		75		$0.00	$0.00	$9.55	$0.00	$0.00	$4.55		-	-	-	0	0	$0	$0	$0
176	>220 - 230	LED		77		$0.00	$0.00	$9.80	$0.00	$0.00	$4.67		-	-	87	87	80	$0	$0	$10,231
177	>230 - 240	LED		80		$0.00	$0.00	$10.18	$0.00	$0.00	$4.85		-	-	-	0	0	$0	$0	$0
178	>240 - 250	LED		84		$0.00	$0.00	$10.69	$0.00	$0.00	$5.09		-	-	290	290	292	$0	$0	$37,201
179	>250 - 260	LED		87		$0.00	$0.00	$11.08	$0.00	$0.00	$5.27		-	-	14	14	15	$0	$0	$1,861

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
180	>260 - 270	LED		91		$0.00	$0.00	$11.59	$0.00	$0.00	$5.51		-	-	-	0	0	$0	$0	$0
181	>270 - 280	LED		94		$0.00	$0.00	$11.97	$0.00	$0.00	$5.70		-	-	18	18	20	$0	$0	$2,586
182	>280 - 290	LED		97		$0.00	$0.00	$12.35	$0.00	$0.00	$5.88		-	-	-	0	0	$0	$0	$0
183	>290 - 300	LED		101		$0.00	$0.00	$12.86	$0.00	$0.00	$6.12		-	-	-	0	0	$0	$0	$0
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								Totals					**56,732**	**15,751**	**76,699**	**149,182**	**40,387**	**$4,538,144**	**$205,643**	**$5,144,159**

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	$5.52	6,301	$417,378
59	Fiberglass, 2-Piece, Black or Bronze	Fiberglass	30	A	$8.98	2,848	$306,900
61	Fiberglass, 2-Piece, Gray	Fiberglass	30	A	$8.98	6,597	$710,893
1	Wood, SLO	Wood	30 to 35	A	$6.70	1,439	$115,696
3	Wood, SLO	Wood	40 to 55	A	$7.87	240	$22,666
58	Fiberglass, 2-Piece, Color may vary	Fiberglass	20	B	$0.18	4,400	$9,504
60	Fiberglass, 2-Piece, Black or Bronze	Fiberglass	30	B	$0.30	4,149	$14,936
62	Fiberglass, 2-Piece, Gray	Fiberglass	30	B	$0.30	6,529	$23,504
46	Wood, SLO	Wood	30 to 35	B	$0.22	156	$412
47	Wood, SLO	Wood	40 to 55	B	$0.26	40	$125
31	Aluminum, Regular, Post-Top	Aluminum	16	A	$5.12	524	$32,195
32	Aluminum, Regular with 4' Arm	Aluminum	25	A	$9.49	3,565	$405,982
33	Aluminum, Regular with 6' Arm	Aluminum	30	A	$10.87	378	$49,306
28	Aluminum, Regular with 8' Arm	Aluminum	35	A	$12.57	229	$34,542
18	Aluminum with 4' Davit Arm	Aluminum	25	A	$10.12	96	$11,658
6	Aluminum with 6' Davit Arm	Aluminum	30	A	$11.37	693	$94,553
29	Aluminum with 8' Davit Arm	Aluminum	35	A	$12.99	720	$112,234
70	Aluminum with 8' Davit Arm	Aluminum	40	A	$16.67	97	$19,404
27	Aluminum with 2-6' Double Davit	Aluminum	30	A	$12.61	86	$13,014
65	Aluminum, Fluted Ornamental, Post-Top	Aluminum	14	A	$8.95	209	$22,447
69	Aluminum, Smooth Techtra Ornamental	Aluminum	18	A	$19.12	559	$128,257
66	Aluminum, Ornamental, Post-Top	Aluminum	16	A	$9.29	616	$68,672
79	Aluminum, Fluted Ornamental, Pendant	Aluminum	18	A	$17.98	97	$20,929
81	Aluminum, Non-Fluted Ornamental, Pendant	Aluminum	18	A	$17.87	1,854	$397,572
85	Fiberglass, 1-Piece, Anchor Base, Color May Va	Fiberglass	25	A	$10.61	4	$509
63	Fiberglass, Ornamental Black	Fiberglass	14	A	$11.80	683	$96,713
83	Fiberglass, 2-Piece, Black or Bronze	Fiberglass	18	A	$5.88	9	$635
67	Fiberglass, Color may vary	Fiberglass	22	A	$4.97	70	$4,175
68	Fiberglass, 2-Piece, Color may vary	Fiberglass	35	A	$8.74	598	$62,718
16	Fiberglass, Anchor Base, Gray or Black	Fiberglass	35	A	$11.89	53	$7,562
35	Fiberglass, Direct Bury with Shroud	Fiberglass	18	A	$7.51	6	$541
34	Aluminum, Regular, Post-Top	Aluminum	16	B	$0.17	52	$106
8	Aluminum, Regular with 4' Arm	Aluminum	25	B	$0.31	749	$2,786
48	Aluminum, Regular with 6' Arm	Aluminum	30	B	$0.36	487	$2,104
54	Aluminum, Regular with 8' Arm	Aluminum	35	B	$0.41	392	$1,929
13	Aluminum with 4' Davit Arm	Aluminum	25	B	$0.33	120	$475
12	Aluminum with 6' Davit Arm	Aluminum	30	B	$0.38	726	$3,311
53	Aluminum with 8' Davit Arm	Aluminum	35	B	$0.43	1,028	$5,304
76	Aluminum with 8' Davit Arm	Aluminum	40	B	$0.55	218	$1,439
14	Aluminum with 2-6' Double Davit	Aluminum	30	B	$0.42	53	$267
71	Aluminum, Fluted Ornamental, Post-Top	Aluminum	14	B	$0.30	1,126	$4,054
75	Aluminum, Smooth Techtra Ornamental	Aluminum	18	B	$0.63	419	$3,168
72	Aluminum, Ornamental, Post-Top	Aluminum	16	B	$0.31	1,119	$4,163
80	Aluminum, Fluted Ornamental, Pendant	Aluminum	18	B	$0.59	438	$3,101
82	Aluminum, Non-Fluted Ornamental, Pendant	Aluminum	18	B	$0.59	230	$1,628
44	Aluminum, Painted Ornamental	Aluminum	35	B	$0.43	60	$310
91	Aluminum, Regular with Breakaway Base, 8' Arm	Aluminum	35	A	$17.94	0	$0

PORTLAND GENERAL ELECTRIC
Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
92	Aluminum, Regular with Breakaway Base, 8' Arm	Aluminum	35	B	$0.59	0	$0
93	Aluminum, Double-Arm, Smooth	Aluminum	25	A	$15.08	0	$0
86	Fiberglass, 1-Piece, Anchor Base, Color May Va	Fiberglass	30	A	$12.94	0	$0
94	Aluminum, Double-Arm, Smooth	Aluminum	25	B	$0.50	0	$0
95	Aluminum, Smooth, Black, Pendant	Aluminum	23	A	$18.31	0	$0
96	Aluminum, Smooth, Black, Pendant	Aluminum	23	B	$0.60	0	$0
88	Fiberglass, 1-Piece, Anchor Base, Color May Va	Fiberglass	25	B	$0.35	15	$63
89	Fiberglass, 1-Piece, Anchor Base, Color May Va	Fiberglass	30	B	$0.43	0	$0
64	Fiberglass, Ornamental Black	Fiberglass	14	B	$0.39	1,434	$6,711
84	Fiberglass, 2-Piece, Black or Bronze	Fiberglass	18	B	$0.19	2	$3
73	Fiberglass, Color may vary	Fiberglass	22	B	$0.16	366	$703
74	Fiberglass, 2-Piece, Color may vary	Fiberglass	35	B	$0.29	1,532	$5,331
17	Fiberglass, Anchor Base, Gray or Black	Fiberglass	35	B	$0.39	81	$379
36	Fiberglass, Direct Bury with Shroud	Fiberglass	18	B	$0.25	351	$1,053
2	Aluminum Post	Aluminum	30	A	$5.06	339	$20,584
30	Concrete, Ornamental Post	Concrete	35 or less	A	$9.38	57	$6,416
37	Steel, Painted Regular	Steel	25	A	$9.38	290	$32,642
38	Steel, Painted Regular	Steel	30	A	$10.72	126	$16,209
39	Wood, Laminated without Mast Arm	Wood	20	A	$5.46	0	$0
24	Wood, Laminated SLO Pole	Wood	20	A	$5.46	0	$0
41	Wood, Curved laminated	Wood	30	A	$7.57	0	$0
11	Wood, Painted Underground	Wood	35	A	$6.63	9	$716
55	Bronze Alloy GardCo	Bronze	12	B	$0.24	0	$0
25	Concrete, Ornamental Post	Concrete	35 or less	B	$0.31	12	$45
7	Steel, Painted Regular	Steel	25	B	$0.31	87	$324
49	Steel, Painted Regular	Steel	30	B	$0.35	1	$4
21	Steel, Unpainted 6-foot Mast Arm	Steel	30	B	$0.35	8	$34
51	Steel, Unpainted 6-foot Davit Arm	Steel	30	B	$0.35	0	$0
40	Steel, Unpainted 8-foot Mast Arm	Steel	35	B	$0.43	188	$970
42	Steel, Unpainted 8-foot Davit Arm	Steel	35	B	$0.43	0	$0
23	Wood, Laminated without Mast Arm	Wood	20	B	$0.18	358	$773
45	Wood, Curved laminated	Wood	30	B	$0.25	57	$171
26	Wood, Painted Underground	Wood	35	B	$0.22	199	$525
				Total Option As		29,392	$3,233,716
				Total Option Bs		27,182	$99,715
						56,574	$3,333,431

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	$20.58	$7.64	$28.22	$20.58	$3.64	$24.22	0	0	$0	$0	$0
21	Cobrahead	MV	175-watt	66	$5.05	$8.40	$13.45	$5.05	$4.00	$9.05	210	166	$12,726	$21,168	$33,894
23	Cobrahead	MV	400-watt	147	$5.27	$18.71	$23.98	$5.27	$8.91	$14.18	341	602	$21,565	$76,561	$98,126
24	Cobrahead	MV	1000-watt	374	$5.90	$47.61	$53.51	$5.90	$22.66	$28.56	51	229	$3,611	$29,137	$32,748
33	Cobrahead - (non-pd)	HPS	70-watt	30	$6.08	$3.82	$9.90	$6.08	$1.82	$7.90	85	31	$6,202	$3,896	$10,098
34	Cobrahead - (non-pd)	HPS	100-watt	43	$5.21	$5.47	$10.68	$5.21	$2.61	$7.82	50	26	$3,126	$3,282	$6,408
35	Cobrahead - (non-pd)	HPS	150-watt	62	$5.29	$7.89	$13.18	$5.29	$3.76	$9.05	9	7	$571	$852	$1,423
39	Cobrahead - (non-pd)	HPS	200-watt	79	$5.81	$10.06	$15.87	$5.81	$4.79	$10.60	21	20	$1,464	$2,535	$3,999
36	Cobrahead - (non-pd)	HPS	250-watt	102	$5.34	$12.99	$18.33	$5.34	$6.18	$11.52	13	16	$833	$2,026	$2,859
41	Cobrahead - (PD)	HPS	310-watt	124	$6.24	$15.79	$22.03	$6.24	$7.51	$13.75	6	9	$449	$1,137	$1,586
37	Cobrahead - (non-pd)	HPS	400-watt	163	$5.57	$20.75	$26.32	$5.57	$9.88	$15.45	767	1,500	$51,266	$190,983	$242,249
30	Flood	HPS	100-watt	43	$5.10	$5.47	$10.57	$5.10	$2.61	$7.71	343	177	$20,992	$22,515	$43,506
38	Flood	HPS	200-watt	79	$5.73	$10.06	$15.79	$5.73	$4.79	$10.52	613	581	$42,150	$74,001	$116,151
31	Flood	HPS	250-watt	102	$7.38	$12.99	$20.37	$7.38	$6.18	$13.56	697	853	$61,726	$108,648	$170,375
32	Flood	HPS	400-watt	163	$7.38	$20.75	$28.13	$7.38	$9.88	$17.26	1,646	3,220	$145,770	$409,854	$555,624
76	Shoebox	HPS	70-watt	30	$5.83	$3.82	$9.65	$5.83	$1.82	$7.65	10	4	$700	$458	$1,158
77	Shoebox	HPS	100-watt	43	$6.43	$5.47	$11.90	$6.43	$2.61	$9.04	444	229	$34,259	$29,144	$63,403
78	Shoebox	HPS	150-watt	62	$6.90	$7.89	$14.79	$6.90	$3.76	$10.66	59	44	$4,885	$5,586	$10,471
81	Special Acorn	HPS	100-watt	43	$11.30	$5.47	$16.77	$11.30	$2.61	$13.91	308	159	$41,765	$20,217	$61,982
82	HADCO - Victorian	HPS	150-watt	62	$11.31	$7.89	$19.20	$11.31	$3.76	$15.07	21	16	$2,850	$1,988	$4,838
49	HADCO - Victorian	HPS	200-watt	79	$9.73	$10.06	$19.79	$9.73	$4.79	$14.52	0	0	$0	$0	$0
83	HADCO - Victorian	HPS	250-watt	102	$9.65	$12.99	$22.64	$9.65	$6.18	$15.83	0	0	$0	$0	$0
40	Early American Post-Top	HPS	100-watt	43	$6.80	$5.47	$12.27	$6.80	$2.61	$9.41	131	68	$10,690	$8,599	$19,288
62	Cobrahead	MH	150-watt	60	$7.61	$7.64	$15.25	$7.61	$3.64	$11.25	9	6	$822	$825	$1,647
48	Cobrahead	MH	175-watt	71	$5.76	$9.04	$14.80	$5.76	$4.30	$10.06	3	3	$207	$325	$533
61	Flood	MH	350-watt	139	$8.64	$17.70	$26.34	$8.64	$8.42	$17.06	304	507	$31,519	$64,570	$96,088
60	Flood	MH	400-watt	156	$5.81	$19.86	$25.67	$5.81	$9.45	$15.26	567	1,061	$39,531	$135,127	$174,659
47	Flood	HPS	750-watt	285	$10.80	$36.28	$47.08	$10.80	$17.27	$28.07	46	157	$5,962	$20,027	$25,988
12	Special Acorn - Independence	HPS	100-watt	43	$10.80	$5.47	$16.27	$10.80	$2.61	$13.41	2	1	$259	$131	$390
64	HADCO Capitol Acorn	HPS	100-watt	43	$13.79	$5.47	$19.26	$13.79	$2.61	$16.40	0	0	$0	$0	$0
65	HADCO Capitol Acorn	HPS	200-watt	79	$14.08	$10.06	$24.14	$14.08	$4.79	$18.87	0	0	$0	$0	$0
66	HADCO Capitol Acorn	HPS	250-watt	102	$13.37	$12.99	$26.36	$13.37	$6.18	$19.55	0	0	$0	$0	$0
98	HADCO Techtra	HPS	100-watt	43	$17.98	$5.47	$23.45	$17.98	$2.61	$20.59	12	6	$2,589	$788	$3,377
99	HADCO Techtra	HPS	150-watt	62	$18.84	$7.89	$26.73	$18.84	$3.76	$22.60	2	1	$452	$189	$642
90	HADCO Westbrooke	HPS	70-watt	30	$12.93	$3.82	$16.75	$12.93	$1.82	$14.75	0	0	$0	$0	$0
91	HADCO Westbrooke	HPS	100-watt	43	$13.21	$5.47	$18.68	$13.21	$2.61	$15.82	0	0	$0	$0	$0
94	HADCO Westbrooke	HPS	250-watt	102	$11.58	$12.99	$24.57	$11.58	$6.18	$17.76	0	0	$0	$0	$0
9	Holophane Mongoose	HPS	150-watt	62	$12.15	$7.89	$20.04	$12.15	$3.76	$15.91	0	0	$0	$0	$0
100	Cobrahead	LED	>30W-35W	11	$5.46	$1.40	$6.86	$5.46	$0.67	$6.13	134	18	$8,780	$2,251	$11,031
101	Cobrahead	LED	>45W-50W	16	$5.31	$2.04	$7.35	$5.31	$0.97	$6.28	423	81	$26,954	$10,355	$37,309
102	Cobrahead	LED	>50W-55W	18	$5.59	$2.29	$7.88	$5.59	$1.09	$6.68	102	22	$6,842	$2,803	$9,645
103	Cobrahead	LED	>65W-70W	23	$5.99	$2.93	$8.92	$5.99	$1.39	$7.38	212	59	$15,239	$7,454	$22,692
104	Cobrahead	LED	>100W-110W	36	$6.23	$4.58	$10.81	$6.23	$2.18	$8.41	211	91	$15,774	$11,597	$27,371
105	Cobrahead	LED	>130W-140W	46	$6.96	$5.86	$12.82	$6.96	$2.79	$9.75	126	70	$10,524	$8,860	$19,384
107	Cobrahead	LED	>170W-180W	60	$8.22	$7.64	$15.86	$8.22	$3.64	$11.86	69	50	$6,806	$6,326	$13,132
108	Cobrahead	LED	>190W-200W	67	$8.18	$8.53	$16.71	$8.18	$4.06	$12.24	302	243	$29,644	$30,913	$60,557
109	Cobrahead	LED	>20W-25W	8	$5.09	$1.02	$6.11	$5.09	$0.48	$5.57	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**
110	Acorn	LED	>45W-50W	16	$10.69	$2.04	$12.73	$10.69	$0.97	$11.66	15	3	$1,924	$367	$2,291
111	Acorn	LED	>65W-70W	23	$12.85	$2.93	$15.78	$12.85	$1.39	$14.24	6	2	$925	$211	$1,136
112	Pendant (non-flare)	LED	53	18	$16.25	$2.29	$18.54	$16.25	$1.09	$17.34	0	0	$0	$0	$0
113	Pendant (non-flare)	LED	69	24	$15.99	$3.06	$19.05	$15.99	$1.45	$17.44	0	0	$0	$0	$0
114	Pendant (non-flare)	LED	85	29	$16.61	$3.69	$20.30	$16.61	$1.76	$18.37	0	0	$0	$0	$0
117	Pendant (flare)	LED	>50W-55W	18	$17.41	$2.29	$19.70	$17.41	$1.09	$18.50	0	0	$0	$0	$0
118	Pendant (flare)	LED	>65W-70W	23	$16.50	$2.93	$19.43	$16.50	$1.39	$17.89	0	0	$0	$0	$0
119	Pendant (flare)	LED	>80W-85W	28	$16.73	$3.56	$20.29	$16.73	$1.70	$18.43	0	0	$0	$0	$0
122	CREE XSP	LED	>20W-25W	8	$5.24	$1.02	$6.26	$5.24	$0.48	$5.72	914	88	$57,472	$11,187	$68,660
123	CREE XSP	LED	>40W-45W	15	$5.24	$1.91	$7.15	$5.24	$0.91	$6.15	5,656	1,018	$355,649	$129,636	$485,285
124	CREE XSP	LED	>45W-50W	16	$5.24	$2.04	$7.28	$5.24	$0.97	$6.21	912	175	$57,347	$22,326	$79,672
125	CREE XSP	LED	>55W-60W	20	$5.30	$2.55	$7.85	$5.30	$1.21	$6.51	2,076	498	$132,034	$63,526	$195,559
126	CREE XSP	LED	>90W-95W	32	$5.82	$4.07	$9.89	$5.82	$1.94	$7.76	873	335	$60,970	$42,637	$103,608
127	Pendant (non-flare)	LED	36	12	$15.00	$1.53	$16.53	$15.00	$0.73	$15.73	0	0	$0	$0	$0
128	Pendant (flare)	LED	>35W-40W	13	$14.59	$1.66	$16.25	$14.59	$0.79	$15.38	0	0	$0	$0	$0
129	Post-Top, American Revolution	LED	>30W-35W	11	$8.04	$1.40	$9.44	$8.04	$0.67	$8.71	68	9	$6,561	$1,142	$7,703
130	Post-Top, American Revolution	LED	>45W-50W	16	$8.04	$2.04	$10.08	$8.04	$0.97	$9.01	1	0	$96	$24	$121
131	HADCO Acorn	LED	70	24	$17.34	$3.06	$20.40	$17.34	$1.45	$18.79	0	0	$0	$0	$0
132	Cobrahead	LED	>150W-160W	53	$8.30	$6.75	$15.05	$8.30	$3.21	$11.51	151	96	$15,040	$12,231	$27,271
133	Cobrahead	LED	>25W-30W	9	$5.09	$1.15	$6.24	$5.09	$0.55	$5.64	164	18	$10,017	$2,263	$12,280
134	Cobrahead	LED	>40W-45W	15	$5.27	$1.91	$7.18	$5.27	$0.91	$6.18	168	30	$10,624	$3,851	$14,475
135	Cobrahead	LED	>85W-90W	30	$6.01	$3.82	$9.83	$6.01	$1.82	$7.83	96	35	$6,924	$4,401	$11,324
137	Acorn	LED	>35W-40W	13	$13.24	$1.66	$14.90	$13.24	$0.79	$14.03	3	0	$477	$60	$536
138	Acorn	LED	>55W-60W	20	$13.24	$2.55	$15.79	$13.24	$1.21	$14.45	37	9	$5,879	$1,132	$7,011
139	Acorn	LED	>70W-75W	25	$13.24	$3.18	$16.42	$13.24	$1.52	$14.76	0	0	$0	$0	$0
141	Flood	LED	>120W-130W	43	$7.84	$5.47	$13.31	$7.84	$2.61	$10.45	228	118	$21,450	$14,966	$36,416
142	Flood	LED	>180W-190W	63	$9.07	$8.02	$17.09	$9.07	$3.82	$12.89	905	684	$98,500	$87,097	$185,597
143	Flood	LED	>370W-380W	127	$13.57	$16.17	$29.74	$13.57	$7.70	$21.27	203	309	$33,057	$39,390	$72,447
144	Flood	LED	>80W-85W	28	$7.29	$3.56	$10.85	$7.29	$1.70	$8.99	67	23	$5,861	$2,862	$8,723
200	Cobrahead	LED	>35W-40W	13	$5.09	$1.66	$6.75	$5.09	$0.79	$5.88	0	0	$0	$0	$0
201	Cobrahead	LED	>55W-60W	20	$5.27	$2.55	$7.82	$5.27	$1.21	$6.48	0	0	$0	$0	$0
202	Cobrahead	LED	>60W-65W	21	$5.27	$2.67	$7.94	$5.27	$1.27	$6.54	0	0	$0	$0	$0
203	Cobrahead	LED	>70W-75W	25	$6.01	$3.18	$9.19	$6.01	$1.52	$7.53	0	0	$0	$0	$0
204	Cobrahead	LED	>75W-80W	26	$6.01	$3.31	$9.32	$6.01	$1.58	$7.59	0	0	$0	$0	$0
205	Cobrahead	LED	>80W-85W	28	$6.01	$3.56	$9.57	$6.01	$1.70	$7.71	0	0	$0	$0	$0
206	Cobrahead	LED	>90W-95W	32	$6.01	$4.07	$10.08	$6.01	$1.94	$7.95	0	0	$0	$0	$0
207	Cobrahead	LED	>95W-100W	33	$6.01	$4.20	$10.21	$6.01	$2.00	$8.01	0	0	$0	$0	$0
208	Cobrahead	LED	>110W-120W	39	$6.01	$4.97	$10.98	$6.01	$2.36	$8.37	0	0	$0	$0	$0
209	Cobrahead	LED	>120W-130W	43	$6.01	$5.47	$11.48	$6.01	$2.61	$8.62	0	0	$0	$0	$0
210	Cobrahead	LED	>140W-150W	50	$8.30	$6.37	$14.67	$8.30	$3.03	$11.33	0	0	$0	$0	$0
211	Cobrahead	LED	>160W-170W	56	$8.30	$7.13	$15.43	$8.30	$3.39	$11.69	0	0	$0	$0	$0
212	Cobrahead	LED	>180W-190W	63	$8.30	$8.02	$16.32	$8.30	$3.82	$12.12	0	0	$0	$0	$0
213	Acorn	LED	>40W-45W	15	$13.24	$1.91	$15.15	$13.24	$0.91	$14.15	0	0	$0	$0	$0
214	Acorn	LED	>50W-55W	18	$13.24	$2.29	$15.53	$13.24	$1.09	$14.33	0	0	$0	$0	$0
215	Acorn	LED	>60W-65W	21	$13.24	$2.67	$15.91	$13.24	$1.27	$14.51	0	0	$0	$0	$0
216	Pendant (flare)	LED	>40W-45W	15	$14.59	$1.91	$16.50	$14.59	$0.91	$15.50	0	0	$0	$0	$0
217	Pendant (flare)	LED	>45W-50W	16	$14.59	$2.04	$16.63	$14.59	$0.97	$15.56	0	0	$0	$0	$0
218	Pendant (flare)	LED	>55W-60W	20	$17.41	$2.55	$19.96	$17.41	$1.21	$18.62	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**
219	Pendant (flare)	LED	>60W-65W	21	$17.41	$2.67	$20.08	$17.41	$1.27	$18.68	0	0	$0	$0	$0
220	Pendant (flare)	LED	>70W-75W	25	$16.50	$3.18	$19.68	$16.50	$1.52	$18.02	0	0	$0	$0	$0
221	Pendant (flare)	LED	>75W-80W	26	$16.73	$3.31	$20.04	$16.73	$1.58	$18.31	0	0	$0	$0	$0
222	CREE XSP	LED	>30W-35W	11	$5.24	$1.40	$6.64	$5.24	$0.67	$5.91	6	1	$377	$101	$478
223	CREE XSP	LED	>65W-70W	23	$5.82	$2.93	$8.75	$5.82	$1.39	$7.21	7	2	$489	$246	$735
224	CREE XSP	LED	>130W-140W	46	$7.26	$5.86	$13.12	$7.26	$2.79	$10.05	2	1	$174	$141	$315
Totals											20,907	13,784	$1,551,350	$1,754,928	$3,306,278
Poles															
1	Wood, SLO	Wood	30 to 35				$6.42				5,903				$454,767
3	Wood, SLO	Wood	40 to 55				$7.59				631				$57,471
11	Wood, Painted Underground	Wood	35				$6.36				1				$76
41	Wood, Curved laminated	Wood	30				$7.51				0				$0
31	Aluminum, Regular, Post-Top	Aluminum	16				$4.91				109				$6,422
32	Aluminum, Regular with 4' Arm	Aluminum	25				$9.14				79				$8,665
33	Aluminum, Regular with 6' Arm	Aluminum	30				$10.52				29				$3,661
28	Aluminum, Regular with 8' Arm	Aluminum	35				$12.22				3				$440
65	Aluminum, Fluted Ornamental, Post-Top	Aluminum	14				$8.74				36				$3,776
18	Aluminum with 4' Davit Arm	Aluminum	25				$9.77				4				$469
6	Aluminum with 6' Davit Arm	Aluminum	30				$11.02				18				$2,380
29	Aluminum with 8' Davit Arm	Aluminum	35				$12.64				1				$152
70	Aluminum with 8' Davit Arm	Aluminum	40				$16.25				0				$0
27	Aluminum with 2-6' Double Davit	Aluminum	30				$12.26				11				$1,618
66	Aluminum, Ornamental, Post-Top	Aluminum	16				$9.08				2				$218
69	Alunimum, Smooth Techtra Ornamental	Aluminum	18				$18.77				19				$4,280
63	Fiberglass, Ornamental Black	Fiberglass	14				$11.52				159				$21,980
57	Fiberglass, 2-Piece, Color may vary	Fiberglass	20				$5.31				376				$23,959
61	Fiberglass, 2-Piece, Gray	Fiberglass	30				$8.63				1,446				$149,748
68	Fiberglass, 2-Piece, Color may vary	Fiberglass	35				$8.46				45				$4,568
16	Fiberglass, Anchor Base, Gray or Black	Fiberglass	35				$11.62				2				$279
35	Fiberglass, Direct Bury with Shroud	Fiberglass	18				$7.17				114				$9,809
79	Aluminum, Fluted Ornamental, Pendant	Aluminum	18				$17.63				0				$0
81	Aluminum, Non-Fluted Ornamental, Pendant	Aluminum	22				$17.52				0				$0
85	Fiberglass, 1-Piece, Anchor Base, Color May Vary	Fiberglass	25				$10.26				0				$0
86	Fiberglass, 1-Piece, Anchor Base, Color May Vary	Fiberglass	30				$12.59				0				$0
91	Aluminum, Regular with Breakaway Base, 8' Arm	Aluminum	35				$17.60				0				$0
93	Aluminum, Double-Arm, Smooth	Aluminum	25				$14.73				0				$0
95	Aluminum, Smooth, Black, Pendant	Aluminum	23				$17.96				0				$0
Totals											8,988				$754,738
Totals Luminaires and Poles															$4,061,015

SCHEDULE XXX
DECOUPLING ADJUSTMENT

PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by weather-normalized variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential Customers and Nonresidential Customers who receive service under Schedules 32, 38, 532 and 538 located within the Company's service territory.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, differences between:

a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) to weather-normalized kWh Energy sales; and

b) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer to the numbers of active Customers for each applicable SNA rate schedule, respectively, for each month. For Schedule 7, a Secondary Fixed Charge equal to 72% of the Monthly Fixed Charge will be used to calculate Fixed Charge Revenues for actual customer counts that exceed the projected customer counts used to establish base rates in a general rate review.

The SNA will calculate monthly as the Fixed Charge Revenue less actual revenues and will accrue to the SNA Balancing Account. The monthly amount accrued may be positive (an under-collection) or negative (an over-collection). The SNA is divided into sub-accounts so that net accruals for each rate schedule will track separately.

The SNA is applicable to the following rate schedules:

Schedule	Fixed Charge Energy Rate (¢ per kWh)	Monthly Fixed Charge	Monthly Secondary Fixed Charge
7	10.470	$83.34	$60.00
32	9.313	$123.81	
38	11.280	$724.72	

SCHEDULE XXX (Continued)

SNA BALANCING ACCOUNT

The Company will maintain a balancing account for the SNA applicable rate schedules. The balancing account will record over- and under-collections resulting from differences as determined, by the SNA mechanism. The account will accrue interest at the Commission-authorized Modified Blended Treasury Rate established for deferred accounts.

DECOUPLING ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate
7	X.XXX ¢ per kWh
32	X.XXX ¢ per kWh
38	X.XXX ¢ per kWh
532	X.XXX ¢ per kWh
538	X.XXX ¢ per kWh

TIME AND MANNER OF FILING

Commencing in 2025 the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the subsequent year based on a) the amounts in the SNA Balancing Account

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers detailing the calculation of the new proposed prices and the SNA weather-normalizing adjustments.

SCHEDULE 123 (Continued)

SPECIAL CONDITIONS

1. The Fixed Charge Energy Rate and Monthly Fixed Charge per Customer will be updated concurrently with a change in the applicable base revenues used to determine the rates.

2. Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that used for determining the forecasted loads used to establish base rates.

3. No revision to the SNA Adjustment Rate will result in an estimated average annual rate increase or decrease greater than 3% to the applicable SNA rate schedule, based on the net rates in effect on the effective date of the Schedule 123 rate revisions. If the amount of the proposed rate revision exceeds the 3% limit, only a 3% rate increase or decrease will be proposed any remaining amount in the SNA Balancing Account will be carried over to the following year(s).

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 90, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91, and 95 are exempt from Schedule 125.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings, including, but not limited to:

- NVPC Modeling Enhancements, and new items
- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Wind energy forecast based on a five-year rolling average.
- Costs associated with wind integration. The battery portion of wind and solar projects that have a battery storage component may be included if the battery is charged solely by wind and solar generation.
- Dispatch of energy storage systems.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs.
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes.

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 1.0357.

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments and modeling enhancements 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 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, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the inal change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) new market power and fuel contracts entered into since the previous updates, 3) the final planned maintenance outages and load forecast from the October 1st filing, 4) final update to Qualifying Facilities online dates, and 5) final price for the energy generation at the Priest Rapids and Wanapum hydro facilities, as provided in the power contract between PGE and Grant County.

SCHEDULE 125 (Concluded)

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

ADJUSTMENT RATES

Schedule		¢ per kWh
7		0.000
15		0.000
32		0.000
38		0.000
47		0.000
49		0.000
75		
	Secondary	0.000 (1)
	Primary	0.000 (1)
	Subtransmission	0.000 (1)
83		0.000
85		
	Secondary	0.000
	Primary	0.000
89		
	Secondary	0.000
	Primary	0.000
	Subtransmission	0.000
90		
	Primary	0.000
	Subtransmission	0.000
91		0.000
92		0.000
95		0.000

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an ~~"~~"automatic adjustment clause~~"~~" as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those who were served on Schedule 76R and 576R, 485, 489, 490, 491, 492, 495, 515, 532, 538, 549, 583, 585, 589, 591, 592, 595 and 689, or served under Schedules 83, 85, 89 or 90 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 590, 591, 592 and 595 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE

~~Subject to the Earnings Test, t~~The Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance deviates from the Baseline Net Variable Power Cost (NVPC).~~exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.~~

Forecast and Actual NVPC subject to the Annual Power Cost Variance Mechanism will exclude NVPC associated with Reliability Contingency Events.

RELIABILITY CONTINGENCY EVENT POWER COST VARIANCE

The Reliability Contingency Event (RCE) Power Cost Variance is the amount that the annual actual NVPC prudently incurred during RCEs deviates from forecast NVPC associated with RCEs. An RCE would qualify for 100% cost recovery or refund into the Power Cost Variance Account when an RCE is called as defined in this tariff.

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 Account.

SCHEDULE 126 (Continued)

POWER COST VARIANCE ACCOUNT (Continued)

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission but with a rolling amortization cap equivalent to 2.5% on an overall customer price basis. Additional amounts accrued beyond the 2.5% cap will be rolled over to subsequent period based on Commission approved amortization schedules including, but not limited to, offsetting of remaining amounts owed to the Company with credit amounts accrued to the Account in subsequent periods. 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 consistent with these concepts. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0357 to account for franchise fees, uncollectibles, and OPUC fees.

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will not be subject to an earnings review for the year that the power costs were incurred. ~~The Company will recover the Adjustment Amount 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 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~~ is calculated based on the following formula:~~the Actual NVPC divided by Actual Loads.~~

(Actual NVPC – RCE NVPC) / (Actual Loads – RCE Loads)

Annual Variance (AV) - The Annual Variance (AV) is the dollar amount calculated annually based on the following formula:

(Actual Unit NVPC – Adjusted Base Unit NVPC) * (Actual Loads – RCE Loads)

SCHEDULE 126 (Continued)

DEFINITIONS (Continued)

Base Unit NVPC - The Base Unit NVPC is the NVPC used to develop rate schedules for the applicable year divided by the associated calendar basis retail loads. Base NVPC are updated annually in accordance with Schedule 125.

Adjusted Base Unit NVPC - The Adjusted Base Unit NVPC is the NVPC used to calculate the Annual Variance. The Adjusted Base Unit NVPC is the Base Unit NVPC (determined in accordance with Schedule 125) adjusted for load and cost changes resulting from non-residential customers choosing service under Schedule 515 through 595 after the November update for the applicable year.

~~Negative Annual Power Cost Deadband - The Negative Annual Power Cost Deadband is ($15.0 million).~~

~~Positive Annual Power Cost Deadband - The Positive Annual Power Cost Deadband is $30.0 million.~~

Net Variable Power Costs (NVPC) - The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Exclude power costs prudently incurred during RCEs.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the relevant ~~deferral~~ period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- 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.

SCHEDULE 126 (Continued)

DEFINITIONS (Continued)

Reliability Contingency Event – An event qualifies as a Reliability Contingency Event (RCE) for cost recovery when 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 1.0357 to account for franchise fees, uncollectibles, and OPUC fees.

~~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.

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.

SCHEDULE 126 (Continued)

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	0.080 ¢ per kWh
15	0.080 ¢ per kWh
32	0.080 ¢ per kWh
38	0.080 ¢ per kWh
47	0.080 ¢ per kWh
49	0.080 ¢ per kWh
75	
Secondary	0.080 ¢ per kWh(1)
Primary	0.080 ¢ per kWh(1)
Subtransmission	0.080 ¢ per kWh(1)
83	0.080 ¢ per kWh
85	
Secondary	0.080 ¢ per kWh
Primary	0.080 ¢ per kWh
89	
Secondary	0.080 ¢ per kWh
Primary	0.080 ¢ per kWh
Subtransmission	0.080 ¢ per kWh
90	
Primary	0.080 ¢ per kWh
Subtransmission	0.080 ¢ per kWh
91	0.080 ¢ per kWh
92	0.080 ¢ per kWh
95	0.080 ¢ per kWh
485	
Secondary	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
489	
Secondary	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
Subtransmission	0.080 ¢ per kWh(2)
490	
Primary	0.080 ¢ per kWh
Subtransmission	0.080 ¢ per kWh

(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
491	0.080 ¢ per kWh
492	0.080 ¢ per kWh
495	0.080 ¢ per kWh
515	0.080 ¢ per kWh(2)
532	0.080 ¢ per kWh(2)
538	0.080 ¢ per kWh(2)
549	0.080 ¢ per kWh(2)
575	
Secondary	0.080 ¢ per kWh(1)
Primary	0.080 ¢ per kWh(1)
Subtransmission	0.080 ¢ per kWh(1)
583	0.080 ¢ per kWh(2)
585	0.080 ¢ per kWh(2)
Seconday	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
589	
Secondary	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
Subtransmission	0.080 ¢ per kWh(2)
590	
Primary	0.080 ¢ per kWh
Subtransmission	0.080 ¢ per kWh
591	0.080 ¢ per kWh(2)
592	0.080 ¢ per kWh(2)
595	0.080 ¢ per kWh(2)
689	
Secondary	0.080 ¢ per kWh(2)
Primary	0.080 ¢ per kWh(2)
Subtransmission	0.080 ¢ per kWh(2)

(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 201 (Continued)

MONTHLY SERVICE CHARGE

Each separately metered QF ~~not associated with a retail Customer account~~ will be charged $~~10.00 per month~~ a Monthly Service Charge as set forth in Schedule 300.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Deferrals and Automatic Adjustment Clause (AAC)

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Jaki Ferchland
Greg Batzler

February 15, 2023

Table of Contents

I. Introduction

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

A. My name is Jaki Ferchland. I am the Manager of Revenue Requirement in Regulatory Affairs at PGE.

My name is Greg Batzler. I am a Senior Regulatory Consultant in Regulatory Affairs at PGE.

Our qualifications are provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain why the current process by which Staff of the Public Utility Commission of Oregon (Staff) requires PGE to file deferral applications when an automatic adjustment clause (AAC) has been established is administratively burdensome and unnecessarily duplicative since the applications should only be required in those circumstances where a deferral is truly warranted under Oregon Revised Statute (ORS) 757.259.

Q. What is PGE proposing?

A. PGE is requesting that the Public Utility Commission of Oregon (Commission) recognize the deferral mechanism as a separate and distinct mechanism from the AAC mechanism.

Specifically, we propose that the nature of PGE's deferrals be treated more accurately so that: 1) deferral applications and reauthorizations would be limited to only those that are specifically required under ORS 757.259; and 2) AACs, which are established under ORS 757.210, be recognized as exceptions to ORS 757.259. This change removes the need for PGE to file annual deferral applications in the following 20 dockets which are or should be AACs: UM 1294, UM 1482, UM 1514, UM 1827, UM 1915, UM 1938, UM 1977, UM

1986, UM 1988, UM 1991, UM 2003, UM 2019, UM 2039, UM 2078, UM 2113, UM 2131, UM 2218, UM 2219, UM 2234, and UM 2249. In this general rate case (GRC) to implement this change, tariff schedules involving AAC mechanisms remove any inapplicable reference to ORS 757.259. Exhibit 1401 provides further details on the specific dockets and tariff schedules at issue.

Q. Why does PGE believe it must make this proposal and obtain a Commission order recognizing this distinction?

A. As explained in more detail below, Staff has taken the position that a deferral is needed for any AAC and balancing account usage. We disagree with this interpretation of the statute and do not believe that there is a sound policy or accounting basis for Staff's position. Instead, deferrals and AACs are separate and distinct.

Q. What distinction is made in the statute between deferred accounting and an AAC?

A. Requests for "deferred accounting" fall strictly under ORS 757.259. When PGE files an application under this statute, it is to request authorization from the Commission, consistent with Financial Accounting Standards (FAS) No. 71,[1] to move costs or revenues from the income statement to the balance sheet to create a regulatory asset or liability for transactions that otherwise would have been recognized in the income statement per accounting standards.[2] Those costs or revenues can then be recovered or refunded through a tariff schedule at a later date, subsequent to an amortization proceeding and a finding that the resultant rates are just

[1] Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation, Effective December 1982, Available at: https://fasb.org/Page/ShowPdf?path=aop_FAS71.pdf&title=FAS+71+%28as+amended%29&acceptedDisclaimer=true&Submit=

[2] Accounting standards per Generally Accepted Accounting Principles and the FERC Uniform System of Accounts, require that expenses and revenues be charged to appropriate accounts that pull to the income statement. However, FAS No. 71 provides that utilities may move costs from the income statement to the balance sheet, should there be a reasonable expectation that the ensuing regulatory assets or liabilities, that pull to the balance sheet, will be recovered in rates (i.e., amortized).

and reasonable. In contrast, costs that are deemed recoverable through AACs are defined as *exceptions* to standard deferral requests by ORS 757.259(5). This is because approval by the Commission of an AAC allows contemporaneous cost recovery based on ORS 757.210 which authorizes "provision of a rate schedule that provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred, taxes paid to units of government or revenues earned by a utility."

Q. Does PGE's proposal limit the Commission's broad discretion to set customer prices?

A. No. As PGE explains below, the Commission will receive the same information to review and approve and will gain the benefit of eliminating redundant and inefficient processes.

Q. How is your testimony organized?

A. In the next section we discuss the key differences between a deferral as defined under ORS 757.259 and an AAC as defined under ORS 757.210, including why this distinction is important. Then, in Section III, we discuss the historical volume of annual PGE deferrals that Staff has required PGE to submit, while supporting our argument that, as a majority of these fall under an AAC, they are redundant in process and, we believe, not required. Finally, we summarize our arguments and request in Section IV.

II. AAC vs. Deferral

Q. You state above that PGE believes it is unnecessary to file a companion deferral for every authorized AAC. Why?

A. That is correct. PGE does not consider there to be a clear legal, policy or accounting basis to require that an approved AAC must have an associated deferral filing. PGE's amortization request under an AAC tariff schedule provides the appropriate conduit and necessary information for a determination of prudence. Furthermore, PGE believes such deferred accounting filings are not appropriate because it causes confusion between these two mechanisms, which are distinctly different. Treating them as if they are one and the same is incorrect.

Q. How is an AAC different from a deferral?

A. A deferral approved under ORS 757.259 (a "259-deferral") is meant to manage certain instances of unforeseen costs between GRCs, while maintaining the general prohibition against retroactive ratemaking. In contrast, an AAC is meant to solve for known activities where the associated costs and/or revenues are recurring but variable or driven by an external tax authority where the collections cannot be included in base rates for jurisdictional reasons.

As such, a 259-deferral is filed prior to or just as expenses are incurred[3] for activities that were unknown and/or unexpected at the time of setting rates for the utility. The costs aggregate into a deferred account, then *later*, the utility files for amortization of the costs in a separate proceeding.

[3] While we reference incurred expenses when describing the use of a 259-deferral, the mechanism can also be applied to revenues received and recorded as a regulatory liability.

In contrast, an AAC is a tariff filed under ORS 757.210 and is meant to allow for the *contemporaneous* collection of costs while the expenses are incurred for the activity and allows for rate increases or decreases to reflect such expenses without a prior hearing. In this way, an AAC is like base rates, which makes sense given that its definition is in the same statute as the one for setting base rates.

Q. How is "deferred accounting" defined under Oregon Administrative Rule (OAR) 860-027-0300 (Deferred Accounting rule)?

A. "Deferred accounting" is defined as the recording of current expenses or revenues in a balance sheet account for *later* reflection in rates as allowed by ORS 757.259.[4]

Q. Please provide an example of a recent PGE deferral under ORS 757.259.

A. In 2020, PGE filed to defer incremental costs and revenues associated with the 2020 Labor Day Wildfire Emergency. The event resulted in severe damage and the associated costs and revenues were deferred into a regulatory asset account. In 2022, PGE filed to amortize the amounts associated with this event and engaged in a proceeding where a prudence review, earnings test and hearing were all a part of the process. Then, in 2023, PGE began amortizing the balance of this account.

Q. Please provide an explanation of the accounting entries for an AAC and how this differs from a deferral.

A. Unlike a deferral where amounts build up and are then *later* included in rates, an AAC is meant to collect costs at the same time as the costs are incurred. To do this, PGE forecasts its expenses for the next year and sets customers' prices to collect the total annual amount based on anticipated loads. Each month the actual costs incurred are netted against the actual

[4] OAR 860-027-0300(1)(b)(A).

revenues. If the netted amounts do not equal zero, an entry is made in the account associated with the activity to show the difference. These differences can be driven by actual costs being higher or lower than forecasted and/or by loads being higher or lower than anticipated.

As an example, Schedule 137 - Solar Payment Option, is used to pay for solar generation produced and sold by residential and commercial customers to PGE as a part of the Photovoltaic Volumetric Incentive Rate Pilot established under ORS 757.365. Purchases will vary every year depending on the amount of solar power generated by customers. As such, each year in November, PGE reviews the prior year's purchases and creates a forecast for the following year based on the data. PGE then completes the tariff rate by layering in any surplus or deficit from the prior year and applying anticipated loads for the next year.

Q. Should the accounting entries that capture the difference between revenues collected and costs incurred each month be considered "deferred accounting" as defined by the Deferred Accounting rule?

A. No. These accounting entries are a part of a mechanism designed to recover fluctuating costs or refund unstable revenues associated with activities that cannot otherwise be captured in base rates. The Deferred Accounting rule defines "amortization" as the inclusion in rates of amounts that are designed to eliminate, *over time*, the balance in an authorized deferred account.[5] In contrast, an AAC serves to eliminate the balance through the collection of costs while they are being incurred. As such, this definition of "amortize" under the Deferred Accounting rule[6] shows that the AAC does not meet the definition and does not fit under the rule.

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[5] OAR 860-027-0300(1)(a).
[6] *Ibid.*

The rule further clarifies and confirms this understanding by stating that "[a]mortization *does not* include the normal positive and negative fluctuations in a balancing account." [Emphasis added.][7]

Q. Does PGE make any accounting entries where costs or revenues that would otherwise flow through the income statement are moved to the balance sheet for amortization to customers that are *not* considered "deferred accounting" as defined by the Deferred Accounting rule?

A. Yes. We have multiple examples of this treatment and will share two here. First, Commission Order No. 01-777 established that gains and losses from the sale of utility property could be recorded into an account that would later be amortized through Schedule 105. There have been many property sales filings approved since 2001 where such gains and losses were amortized through Schedule 105 and never has the OPUC required PGE to file a deferral prior to recording these amounts.

Second, PGE defers the revenues it receives from the Bonneville Power Administration for the residential exchange credit and amortizes the amounts within the balancing account to customers through Schedule 102.

Q. Does either ORS 757.210 or ORS 757.259 define an AAC as a type of deferral?

A. No. ORS 757.259 does not include any definition for an AAC. ORS 757.210 defines an AAC as:

> A provision of a rate schedule that provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred, taxes paid to units of government or revenues earned by a utility and that is subject to review by the commission at least once every two years.

[7] *Ibid.*

Q. Does ORS 757.259 include language that would otherwise indicate an AAC should be treated as a deferral?

A. No. In fact, the only reference to an AAC in the deferral statute is to establish that it is *not* to be treated in the same manner as a deferral.

Q. In what way is an AAC not to be treated in the same manner as a deferral?

A. ORS 757.259 says that "[u]nless it is subject to an automatic adjustment clause," expenses or revenues deferred are subject to an earnings review at the time of application to amortize the deferral.

Q. Doesn't the reference to the AAC in the deferral statute suggest that an activity can be covered by both a deferral and an AAC, otherwise, why make the distinction?

A. We agree that when costs are initially incurred that could be subject to an AAC, a deferral can be filed to set aside the costs or revenues into a regulatory asset or liability account until such time that an AAC tariff can be filed and approved. Under those circumstances, there is a need to address retroactive ratemaking concerns. However, once the AAC tariff is in place, costs or revenues would be collected or refunded contemporaneously and the deferral would no longer be needed to address retroactive ratemaking. The language in ORS 757.259 makes it clear that under such circumstances, the costs or revenues would not be subject to an earnings review as they would be if they were a part of a 259-deferral.

Q. Is there any other indication that the inclusion of the AAC reference in ORS 757.259 is only meant to clarify how the bridge period should work?

A. Yes. ORS 757.210, which defines the AAC, specifically states that a prudence review should be conducted no less than every two years. However, ORS 757.259, which defines 259-deferrals, states that amounts must be reauthorized every twelve months. It is illogical to have two different time periods established for each of these mechanisms if they are to be treated as the same.

Q. Would removing the deferral application/reauthorization process for AACs remove the Commission's ability to evaluate the recovery of costs in customer prices?

A. No. As we state above, it is simply removing redundant processes. Once costs associated with an activity have already been established as recoverable, the need to reapply through multiple annual deferral applications when the information is already provided through the prudence review of a tariff update is unnecessary. PGE's request does not impact or impede the Commission's ability to review all costs (forecasted and actuals) for prudence.

III. PGE Deferral Growth History and Impact

Q. You have stated that deferral filings associated with AACs result in redundant processes. How is this impacting PGE?

A. In recent years PGE has seen an increase in the number of annual deferral authorizations it makes for the recovery or refund of costs or revenues, which can otherwise be included in base rates. These frequent and unnecessary filings require time and resources (for PGE and for the Commission), which could better be spent on work related to realizing state decarbonization goals, customer focused programs, low-income programs, etc.

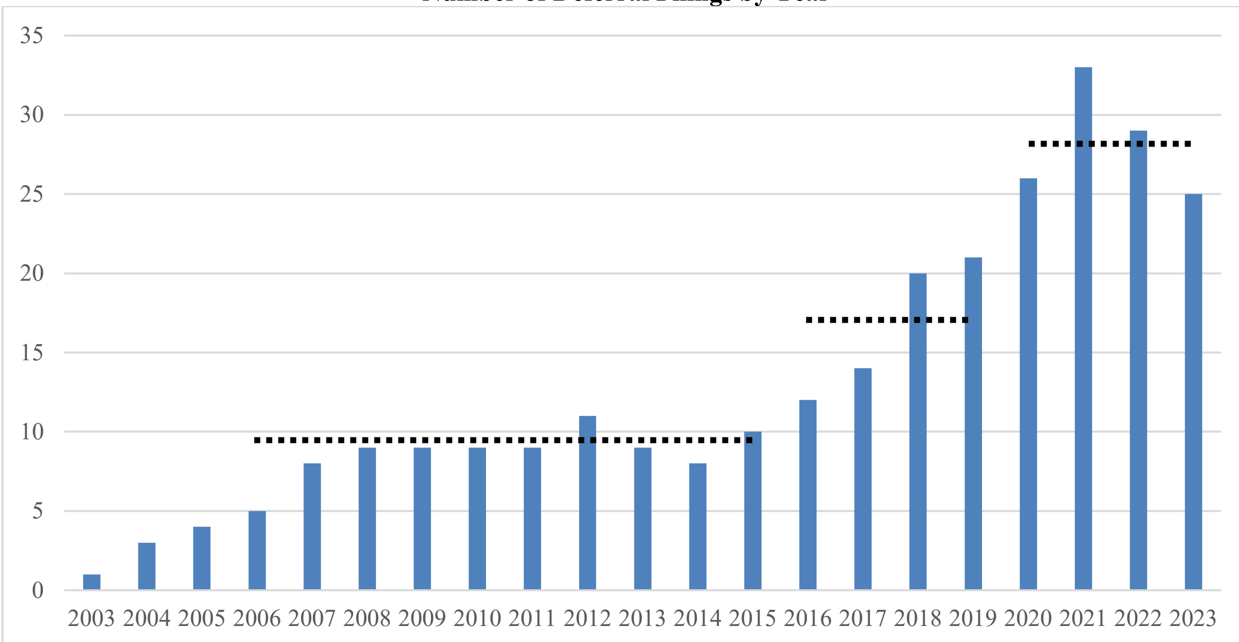
Q. How many deferral authorization applications did PGE file in 2022?

A. PGE filed 29 deferral authorization applications in 2022, as listed in supporting Exhibit 1401, and we will have at least 25 deferral authorization applications in 2023.

Q. How does this number compare to prior years?

A. As shown in Figure 1 below, for the 10-year period from 2006 to 2015, PGE's deferral count was stable at approximately nine deferrals a year. This average jumped to 17 deferrals per year from 2016 to 2019. It then jumped again to approximately 28 per year from 2020 through 2023 (assuming only 25 deferral filings as anticipated in 2023).

Figure 1
Number of Deferral Filings by Year



Q. Why did the number of deferral authorization requests begin to grow?

A. They grew for several reasons. In 2016, SB 1547 led to multiple pilots/programs for transportation electrification and community solar – which allowed for cost recovery of the amounts and led to the addition of three deferrals.[8,9] Then, beginning in 2018, Staff began requiring deferral authorizations for a broader set of topics, all of which are related to routine and required balance sheet entries rather than topics that are unanticipated and/or extraordinary. This position led to the addition of four more unnecessary deferrals. In 2021, various legislation led to the need for four more ongoing AACs, which, under Staff's interpretation means four more annual deferral filings. Of the 25 deferral authorization applications we anticipate filing in 2023, none relate to expenditures for unanticipated and/or extraordinary events, and all will be reauthorizations from the prior year.

[8] 79th Oregon Legislative Assembly - 2016 Regular Session. Enrolled. Senate Bill 1547, Docket No. UM 1811, Order No. 18-054.
[9] All of these resulted in deferrals filed under Docket Nos. UM 1938, UM 1977, and UM 2003.

Q. Please describe further how Staff began requiring deferral authorizations for more topics.

A. In Docket No. UE 319 (UE 319), Staff asserted that PGE needed to file a deferral authorization application for its major maintenance accruals (MMA), which are established and approved in a GRC and are collected through base rate schedules. PGE did not and does not agree with this position, but as part of the settlement process, acquiesced. PGE sees the MMA deferral as a very clear example of an unnecessary and inefficient process for costs established and approved through a GRC order that do not change until the next GRC.

After the UE 319 GRC, Staff then took the position that PGE must file deferrals for items recorded through balancing accounts. Again, PGE did not agree with this approach, but conceded to avoid a dispute.

Q. What did Staff state about deferred accounting in UE 319?

A. In UE 319, Staff said that because workpapers described PGE's treatment of major maintenance expense as a deferral, "PGE may be deferring expenses without filing a request to defer under ORS 757.259."[10]

Q. What deferrals were added because of Staff's position on deferred accounting in UE 319?

A. In addition to the MMA deferral, we were required to file deferrals for PGE's energy efficiency program, Multnomah County Business Income Tax (MCBIT), and the Metro Supportive Housing Services tax. It is possible that more deferrals could be necessary in the future given Staff's position. At this time, PGE is annually filing four deferrals where an amortization filing is never necessary.

[10] UE 319, Staff Exhibit 700.

Q. Has this overall growth in deferral authorization applications caused an administrative burden for PGE?

A. Yes. PGE spends time tracking the authorization dates of each annual deferral. An analyst must take time to create an annual application, and management and legal must take time to review each application. Most of the 25+ deferral applications filed each year would not be necessary under PGE's interpretation. Each unnecessary deferral detracts from PGE's efforts in other spaces.

Q. Has it also been suggested that growth in deferral authorization filings is causing an administrative burden at the Commission?

A. Yes. Staff must review each filing and prepare a Staff report for each deferral application recommending approval (or rejection) of costs to accrue within a balance sheet account. After actual costs have accrued in the account, an advice filing is made to request amortization of those costs. The advice filing is reviewed for prudence and another report is issued by Staff. With numerous annual deferrals, Staff will necessarily need more time and effort to perform the reviews and prepare reports.

Q. Has the Commission expressed interest in the number of PGE deferrals?

A. Yes. In PGE's last rate case, Docket No. UE 394 (UE 394), after filing our opening testimony, but prior to the opening testimony of parties, the Commission issued a bench request for information regarding PGE's deferral filings. Specifically, the Commission was seeking to understand how many deferrals PGE has, what the deferrals covered, and how much each deferral sought to collect from or refund to customers.

Q. Did Staff provide testimony regarding the number of deferral filings in PGE's last GRC?

A. Yes. In UE 394, Staff provided testimony highlighting PGE's large number of deferrals, but did not make any recommendations to reduce the number of deferrals or the amount of costs included in deferrals. However, they did invite PGE to make our own proposal regarding our numerous deferrals.[11]

Q. Did PGE make any proposals in the last GRC regarding the issue of its total deferral count?

A. No. We did not have a recommendation at the time. We are taking the opportunity in this GRC to address the large number of deferrals, how the associated costs and revenues in regulatory balance sheet accounts should be viewed, and how to reduce the administrative burden these deferrals are causing both PGE and Staff.

Q. If recognized, how would PGE's proposal impact its filings to the Commission?

A. In general, it would significantly reduce the number of filings PGE would need to make and the number of filings Staff would need to review, resulting in a considerable reduction to the administrative burden. Again, PGE is currently anticipating at least 25 deferral authorizations applications in 2023. None of these filings are for extraordinary events and all are expected to be authorized yet again in 2024, and these authorizations will all be part of annual advice filings.

Q. How does PGE's proposal result in a reduced administrative burden for PGE and Staff?

A. It eliminates redundant, inefficient, and unnecessary process. As described above, a deferral requires PGE to make both deferral and advice filings, and it requires of Staff a review of costs to be deferred and a later review of the actual costs incurred when the advice filing is

[11] UE 394, Staff Opening Testimony, Exhibit 1100, at Moore/14 – Moore/15.

made. This process is redundant for an AAC because the advice filing carries with it a prudence review of the actual costs *and the forecasted costs* – these forecasted costs *are* the basis of Staff's review of the associated deferral. This means that the Commission has access to and reviews the same information for the forecasted amounts included in an AAC advice filing as it does for the associated deferral filing.

Of the 25 deferral reauthorizations to be filed in 2023, 20 are tied to an AAC. After accounting for deferrals that are collected through the same schedule,[12] PGE will make 43 filings in 2023, and Staff will write 43 reports. If these mechanisms were treated as separate and distinct, PGE would only have five deferral filings and the total number of filings would drop to 25. This also means that Staff's workload would be reduced from 43 deferral and advice filing reports to 25.

[12] E.g., UM 1514, UM 1827, and UM 2234 are collected through Schedule 135.

IV. Summary

Q. Please summarize your proposal.

A. PGE is requesting that the Commission recognize the deferral mechanism as a separate and distinct mechanism from the AAC mechanism because each serves a different purpose. Specifically, we request the Commission clarify that: 1) deferral applications and authorizations would be limited to only those that are specifically required under ORS 757.259; and 2) AACs, which are established under ORS 757.210, be recognized as exceptions to ORS 757.259 and would only require a deferral application to the extent that costs subject to an AAC are being incurred prior to the establishment of an AAC tariff, at which point the deferral is no longer needed. For AACs that are established, PGE would only be required to file for amortization requests under the applicable tariff schedule. All filings, whether a 259-deferral or an AAC, would still undergo a prudence review by the Commission.

With the Commission's recognition of this distinction between the two mechanisms, PGE will no longer perform the unnecessary and inapplicable 25 deferral application process for the following dockets: UM 1294, UM 1482, UM 1514, UM 1827, UM 1938, UM 1977, UM 1986, UM 1988, UM 1915, UM 1991, UM 2003, UM 2019, UM 2039, UM 2078, UM 2113, UM 2131, UM 2218, UM 2219, UM 2234, and UM 2249.[13]

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

A. PGE's proposal will treat deferrals consistent with ORS 757.259 and ORS 757.210, which distinguish a 259-deferral from an AAC. PGE's proposal will also ease the administrative burden (on both PGE and the Commission) of preparing and reviewing duplicative and

[13] *See* Exhibit 1401 for identification of topic for each docket.

overlapping requests, while in no way limiting the Commission's ability to investigate and determine the prudence of the costs or revenues at issue.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1401	PGE Deferrals

Anticipated 2023 Deferrals

Deferral	Description	Schedule	Current	Future
UM 1103	Intervenor Funding	Schedule 105	Deferral	Deferral
UM 1294	PCAM [Annual Power Costs Variance]	Schedule 126	Deferral	AAC*
UM 1301	Direct Access Open Enrollment	Schedule 128 & 129	Deferral	Deferral
UM 1482	Feed In Tariff/Volumetric Incentive Rate Pilot	Schedule 137	Deferral + AAC	AAC
UM 1514	Automated DR	Schedule 135	Deferral + AAC	AAC
UM 1789	Environmental Remediation Costs (Portland Harbor)	Shcedule 149	Deferral	Deferral**
UM 1827	DR Water Heater Pilot	Schedule 135	Deferral + AAC	AAC
UM 1915	MMA Balancing Accounts	Base Rates	Deferral	Base Rates
UM 1938	Transportation Electrification Pilots	Schedule 150	Deferral	AAC
UM 1977	Community Solar Costs	Schedule 136	Deferral+AAC	AAC
UM 1986	MCBIT Balancing Account	Schedule 106	Deferral+AAC	AAC
UM 1988	Qualifying Facilities	Schedule 125	Deferral+AAC	AAC
UM 1991	R&D Tax Credits	Schedule 105	Deferral+AAC	AAC
UM 2003	EV Charging 2019	Schedule 150	Deferral	AAC
UM 2019	WM AAC	Schedule 151	Deferral+AAC	AAC
UM 2039	EE Customer Service Balancing Account	Schedule 110	Deferral+AAC	AAC
UM 2046	OPUC Fee Deferral	Schedule 105	Deferral	Deferral
UM 2078	Residential Battery Storage Deferral	Schedule 138	Deferral+AAC	AAC
UM 2113	Energy Storage_BPSC Microgrid	Schedule 138	Deferral+AAC	AAC
UM 2131	MSHS Tax Deferral	Schedule 103	Deferral+AAC	AAC
UM 2184	RFP IE Consults	Schedule 105	Deferral	Deferral
UM 2218	TE Charge 1/4 of 1%	Schedule 150	Deferral+AAC	AAC
UM 2219	Energy Affordability Act (IQBD)	Schedule 118	Deferral+AAC	AAC
UM 2234	Multi-Year Flexible Load Plan	Schedule 135	Deferral+AAC	AAC
UM 2249	CBIAG	Schedule 153***	Deferral+AAC	AAC

* This schedule should become an AAC under PGE's proposed PCAM in this general rate case; under the prior design the schedule was requested as an AAC, but the ultimate mechanism adopted does not function as an AAC.
** This schedule was requested as an AAC, but the ultimate mechanism adopted does not function as an AAC.
*** Approval pending.

2021

Docket No.	Description
UM 1103	Intervenor Funding
UM 1294	NVPC Costs
UM 1301	Direct Access
UM 1417	Decoupling LRRA-SNA
UM 1482	Photovoltaic VIR
UM 1514	Automated DR
UM 1708	2 DR Pilots
UM 1789	Portland Harbor
UM 1827	DR Water Heater Pilot
UM 1915	MMA (Major Maintenance Expenses)
UM 1938	TE Retail Charging
UM 1976	DER Test Beds
UM 1977	Community Solar
UM 1986	MCBIT
UM 1988	Actual and Forecasted QF
UM 1991	R&D Income Tax Credits
UM 2003	EV Charging
UM 2019	Wildfire Risk Mitigation
UM 2037	Oregon Corporate Activities Tax
UM 2039	Energy Efficiency Customer Service
UM 2046	OPUC Fee Deferral
UM 2064	COVID-19 Costs
UM 2078	Residential Battery Storage Deferral
UM 2113	Energy Storage BPSC Microgrid
UM 2115	Wildfire Emergency 2020
UM 2131	Metro Supportive Housing Tax
UM 2156	February Ice Storm 2021
UM 2181	Pre Filed Emergency Deferral
UM 2184	RFP IE and 3rd Party Consultant
UM 2190	Pre Filed Emergency Account
UM 2217	FERC OATT Refund
UM 2218	TE Charge
UM 2219	Energy Affordability Act

2022

Docket No.	Description
UM 1103	Intervenor Funding
UM 1294	NVPC Costs
UM 1301	Direct Access
UM 1482	Photovoltaic VIR
UM 1514	Automated DR
UM 1789	Portland Harbor
UM 1827	DR Water Heater Pilot
UM 1915	MMA (Major Maintenance Expenses)
UM 1938	TE Retail Charging
UM 1977	Community Solar
UM 1986	MCBIT
UM 1988	Actual and Forecasted QF
UM 1991	R&D Income Tax Credits
UM 2003	EV Charging
UM 2019	Wildfire Risk Mitigation
UM 2039	Energy Efficiency Customer Service
UM 2046	OPUC Fee Deferral
UM 2064	COVID-19 Costs
UM 2078	Residential Battery Storage Deferral
UM 2113	Energy Storage BPSC Microgrid
UM 2131	Metro Supportive Housing Tax
UM 2184	RFP IE and 3rd Party Consultant
UM 2217	FERC OATT Refund
UM 2218	TE Charge
UM 2219	Energy Affordability Act
UM 2234	Multi-Year Flex Load Plan
UM 2249	Community Benefits Impact Analysis Group
UM 2263	BPA RDC_PTP Deferral
UM 2271	Emergency Restoration Costs (Withdrawn)

2023

Docket No.	Description
UM 1103	Intervenor Funding
UM 1294	NVPC Costs
UM 1301	Direct Access
UM 1482	Photovoltaic VIR
UM 1514	Automated DR
UM 1789	Portland Harbor
UM 1827	DR Water Heater Pilot
UM 1915	MMA (Major Maintenance Expenses)
UM 1938	TE Retail Charging
UM 1977	Community Solar
UM 1986	MCBIT
UM 1988	Actual and Forecasted QF
UM 1991	R&D Income Tax Credits
UM 2003	EV Charging
UM 2019	Wildfire Risk Mitigation
UM 2039	Energy Efficiency Customer Service
UM 2046	OPUC Fee Deferral
UM 2078	Residential Battery Storage Deferral
UM 2113	Energy Storage BPSC Microgrid
UM 2131	Metro Supportive Housing Tax
UM 2184	RFP IE and 3rd Party Consultant
UM 2218	TE Charge
UM 2219	Energy Affordability Act
UM 2234	Multi-Year Flex Load Plan
UM 2249	Community Benefits Impact Analysis Group